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February 19, 2003

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
FEB 2003
PUBLIC SERVICE COMMISSION

RE: ***P.S.C. Case No. 2002-00475***

Dear Mr. Dorman:

Enclosed please find and accept for filing Responses of Kentucky Power Company d/b/a American Electric Power to the Staff's data requests. Copies are being served on Counsel for KIUC and the Attorney General.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

Mark R. Overstreet

KE057:KE157:8739:FRANKFORT

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE**

**PUBLIC SERVICE COMMISSION OF KENTUCKY**



**IN THE MATTER OF:**

| | |
|---|---|
| **APPLICATION OF KENTUCKY POWER COMPANY** | **)** |
| **d/b/a AMERICAN ELECTRIC POWER, FOR** | **)** |
| **APPROVAL, TO THE EXTENT NECESSARY,** | **)** |
| **TO TRANSFER FUNCTIONAL CONTROL OF** | **)CASE NO. 2002-00475** |
| **TRANSMISSION FACILITIES LOCATED IN** | **)** |
| **KENTUCKY TO PJM INTERCONNECTION, L.L.C.** | **)** |
| **PURSUANT TO KRS 278.218** | **)** |

**RESPONSES OF KENTUCKY POWER**
**D/B/A**
**AMERICAN ELECTRIC POWER**

**COMMISSION STAFF FIRST SET DATA REQUESTS**

**February 19, 2003**

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Was the decision by American Electric Power, Inc. ("AEP") for its utility subsidiaries to join PJM Interconnection, LLC ("PJM") based on a cost/benefit analysis? If yes, provide the analysis. If no, explain why an analysis was not performed.

**RESPONSE**

No cost/benefit analysis has been conducted to evaluate the benefits of joining an RTO as compared to not joining an RTO because AEP is required to participate in an RTO as a condition of FERC's approval of its merger with the former Central and South West Corporation. An analysis of AEP East's RTO alternatives was conducted and is attached.

**WITNESS**: J. Craig Baker

# PJM and Alliance Companies

# Issues for Discussion with AEP Management

May 3, 2002

# PJM Administration Costs

| PJM Incremental Admin Costs for Alliance Cos. | AEP ($M) | 4-company Alliance ($M) | 8-company Alliance ($M) |
|---|---|---|---|
| Start-up Project Capital Cost | 32.8 | 51.5 | 70.8 |
| Start-up Project Expenses | 18.1 | 28.8 | 39.2 |
| Total Start-up Project Cost | 50.9 | 80.3 | 110.0 |
| Ongoing Annual Cost, Capital and O&M (excluding start-up project expenses) | 40.5 | 58.5 | 81.0 |
| PJM 2003 Admin Budget ($M) * | 174.0 | 174.0 | 174.0 |
| PJM Budget w/ Alliance Members ($M) | 214.5 | 232.5 | 255.0 |

* PJM 2004 Budget projected at $192 M.

# Projected PJM Admin Costs w/ AEP

| Item Description | 9-mo. 2003 | 2004 | 2005 |
|---|---|---|---|
| PJM Admin Costs Present Members ($M) | 131 | 192 | 191 |
| Present PJM Load (TWh) | 267 | 362 | 367 |
| Projected PJM Admin Rate ($/MWh) | .489 | .530 | .520 |
| AEP Load (TWh) | 105 | 143 | 146 |
| Incremental PJM Admin Costs w/ AEP ($M) | 30 | 42 | 43 |
| Revised PJM Admin Costs w/ AEP ($M) | 161 | 234 | 234 |
| PJM Load w/ AEP (TWh) | 372 | 505 | 513 |
| PJM Admin Rate ($/MWh) | .433 | .463 | .456 |
| AEP's PJM Admin Charges ($M) * | 45 | 66 | 66 |
| PJM's Admin Savings ($M) | 15 | 24 | 23 |

* PJM Start-up Expenses charged to AEP are additional costs to be recovered in Transmission rates.

# Projected PJM Admin Costs w/ 4 Companies

| Item Description | 9-mo. 2003 | 2004 | 2005 |
|---|---|---|---|
| PJM Admin Costs Present Members ($M) | 131 | 192 | 191 |
| Present PJM Load (TWh) | 267 | 362 | 367 |
| Projected PJM Admin Rate ($/MWh) | .489 | .530 | .520 |
| 4-Company Load (TWh) | 245 | 333 | 339 |
| Incremental PJM Admin Costs w/ 4 ($M) | 44 | 60 | 62 |
| Revised PJM Admin Costs w/ 4 ($M) | 175 | 252 | 253 |
| PJM Load w/ 4 Companies (TWh) | 512 | 695 | 706 |
| PJM Admin Rate ($/MWh) | .342 | .363 | .358 |
| AEP's PJM Admin Charges ($M) * | 36 | 52 | 51 |
| PJM's Admin Savings ($M) | 39 | 60 | 59 |

* PJM Start-up Expenses charged to AEP are additional costs to be recovered in Transmission rates

# Projected PJM Admin Costs w/ 8 Companies

| Item Description | 9-mo. 2003 | 2004 | 2005 |
|---|---|---|---|
| PJM Admin Costs Present Members ($M) | 131 | 192 | 191 |
| Present PJM Load (TWh) | 267 | 362 | 367 |
| Projected PJM Admin Rate ($/MWh) | .489 | .530 | .520 |
| 8-Company Load (TWh) | 384 | 521 | 531 |
| Incremental PJM Admin Costs w/ 8 ($M) | 61 | 83 | 86 |
| Revised PJM Admin Costs w/ 8 ($M) | 192 | 275 | 277 |
| PJM Load w/ 8 Companies (TWh) | 651 | 883 | 898 |
| PJM Admin Rate ($/MWh) | .295 | .311 | .308 |
| AEP's PJM Admin Charges ($M) * | 31 | 44 | 45 |
| PJM's Admin Savings ($M) | 52 | 79 | 78 |

* PJM Start-up Expenses charged to AEP are additional costs to be recovered in Transmission rates.

# Projected PJM Administration Costs

| Item Description | 9-mo. 2003 | 2004 | 2005 |
|---|---|---|---|
| **With AEP Alone:** | | | |
| AEP's PJM Admin Charges ($M) * | 45 | 66 | 66 |
| PJM's Admin Savings ($M) | 15 | 24 | 23 |
| **With AEP, DPL, FE & VP:** | | | |
| AEP's PJM Admin Charges ($M) * | 36 | 52 | 51 |
| PJM's Admin Savings ($M) | 39 | 60 | 59 |
| **With 8 Alliance Companies:** | | | |
| AEP's PJM Admin Charges ($M) * | 31 | 44 | 45 |
| PJM's Admin Savings ($M) | 52 | 79 | 78 |

* PJM Start-up Expenses charged to AEP are additional costs to be recovered in Transmission rates.

# Rate Analysis

| Description | 8-company Alliance | AEP | 4-company Alliance * |
|---|---|---|---|
| | | | |
| Revenue Neutral Rate | 1.74 | 1.58 | 1.42 |
| w/ PJM Start-up Expenses | 1.82 | 1.63 | 1.48 |
| Including Lost Revenues | 2.98 | 1.78 | 1.71 |

* Data is not available to complete this analysis accurately.

# Cost Benefit Analysis

| Description ($Millions) | AEP Transmission Owner |
|---|---|
| Revenue Neutrality Philosophy | Y |
| TOs responsible for Rate Design | Y |
| Impact on Through & Out Revenues (2) | (4) |
| Annual Admin Charges (1) | 30 to 37 |
| Savings to AEP Operations | 1 |
| Impact on AEP Energy Marketing | Studies in Progress |

(1) PJM Administrative Costs include Energy Market & Control Area Services.

(2) Assumes PJM RTOR $2.065.

# Cost Benefit Analysis

| Description ($Millions) | AEP Alliance GridCo | | AEP Transmission Owner | |
|---|---|---|---|---|
| | MISO | PJM | MISO | PJM |
| Revenue Neutrality Philosophy | N | Y | N | Y |
| TOs responsible for Rate Design | N | Y | N | Y |
| Impact on Through & Out Revenues (2) | (13) to (68) | (4) | (20) to (82) | (4) |
| Annual Admin Charges (1) | 28+ | 47 | 27+ | 30 to 37 |
| Savings to AEP Operations | 1 | 1 | 1 | 1 |
| Impact on AEP Energy Marketing | Studies in Progress | | | |

(1) PJM Administrative Costs include Energy Market & Control Area Services.

(2) Assumes MISO RTOR \$2.13, PJM RTOR \$2.065.

# Analysis

| Description | Revenue in $Millions | Rate in $/kW-month | Equivalent monthly BDs |
|---|---|---|---|
| AEP | 182 | 1.420 | 128 |
| PJM | 85 | 2.065 | 41 |
| PJM with AEP | 267 | 1.580 | 169 |
| | | | |
| | | | |
| | | | |
| | | | |

AMERICAN ELECTRIC POWER
AEP: America's Energy Partner

Date June 11, 2002

Subject RTO Analysis

From R.W. Bradish / C. E. Zebula

To File

Summary

Recently, AEP contracted with A. T. Kearney to undertake an abbreviated study to assess the relative economic impact on AEP of joining either the Midwest ISO or the PJM ISO. Based on the findings there appears to be an economic benefit to AEP for joining the PJM ISO relative to the Midwest ISO. While the study only examined one year and considered only a limited number of scenarios, the results are considered to be robust with the magnitude of the relative differences heavily dependent on the study assumptions.

Study Approach

The objective of the study was to assess the relative economic impact of AEP joining the Midwest ISO versus the economic impact of AEP joining the PJM ISO. In conducting the study, A. T. Kearney used their proprietary version of the GE MAPS model to assess the economics of the following three scenarios:

1. All members of the proposed Alliance RTO joining the PJM ISO except for Ameren.
2. All members of the proposed Alliance RTO joining the Midwest ISO except for First Energy and Dominion Virginia Power.
3. Splitting the proposed Alliance RTO with the Illinois companies joining the Midwest RTO and the remainder joining the PJM ISO.

The study was designed to be performed quickly and the results are very much dependent on a large range of assumptions including RTO footprints, wheeling rates along the RTO seams, environmental regulations, new supply forecast, approach to congestion management, operating reserves, capacity requirements, etc. As such, the focus of the study was to compare the relative economic impacts of the three scenarios. No effort was made to benchmark the results against the existing market structures or to forecast potential revenue streams.

Findings

The following summarizes the results of the analysis:

- Locational marginal prices in AEP are higher under Scenario 1 relative to Scenario 2.

- Locational marginal prices are lower for FE and PJM under Scenario 1 relative to Scenario 2
- Prices throughout the rest of the eastern interconnection indicated only slight variations between Scenario 1 and Scenario 2.
- AEP exports more to the eastern markets under Scenario 1 versus Scenario 2
- Higher gas prices and NOx prices do not change the direction of the conclusions
- Other Alliance members' decisions affect the magnitude of AEP margins, but not the direction

These findings from the study are considered robust, but the magnitude of the relative changes depend significantly on:

- Wheeling rates (the lower they are, the less difference the choice of pool makes)
- Gas-coal differentials (the lower they are, the less difference the choice of pool makes)
- RTO treatment of the interfaces with other pools (can move the results in either direction).

Major Issues

Given the approach followed in the analysis, it became clear that the driver of the results is the placement and treatment of the seam between RTOs. Transmission wheeling charges between RTOs create a financial constraint to the movement of power between the regions and impact the locational marginal prices. The lower the wheeling charge between RTOs the less difference it makes in the decision as to which RTO a company should join.

Conclusions

Based on the results of this analysis, it appears there is an economic benefit to AEP for joining the PJM ISO relative to the Midwest ISO. This conclusion should be considered as an input to a larger decision making framework designed to guide AEP in determining which RTO it should commit to join.

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Was a cost/benefit analysis performed to analyze the impact on Kentucky Power of AEP's joining PJM? If yes, provide the analysis. If no, explain why an analysis was not performed.

**RESPONSE**

An analysis was conducted for the AEP System (See response to Question No. 1), but there was no specific analysis on the impact on KPCo or any other particular operating company. The AEP System is operated as an integrated system, so a system-wide analysis is more appropriate. See also the Company's response to Question No. 1.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Provide a detailed explanation of the consideration given to joining the Midwest ISO ("MISO") or another Regional Transmission Organization ("RTO") other than PJM. Was a cost/benefit analysis of joining MISO performed? If yes, provide the analysis. If no, explain why an analysis was not performed.

**RESPONSE**

In addition to the analysis discussed in the response to Question No.1, the following considerations were given to joining PJM:
Reduction in regulatory uncertainty;
PJM's proven experience in operating as a fully functional RTO including the energy market, which is expected to reduce the risk associated with the functional control transfer and operation of one of the largest transmission assets in the country;
Likelihood of a better agreement on key rate matters with the transmission owners than with MISO transmission owners, lower administrative costs, and improved trading opportunities in an already fully functioning energy and ancillary service market;
PJM had proven experience in integrating new members.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Provide a copy of every document and analysis relied upon by AEP to join PJM rather than MISO.

**RESPONSE**

Please see responses to Questions Nos. 1 and 3. Also, AEP studied the transmission owners' agreements and transmission tariff and rate designs in PJM and MISO. These documents are available on the PJM and MISO website at PJM.com and Midwestiso.org, respectively.

**WITNESS:** J. Craig Baker

**Kentucky Power**
**d/b/a**
**American Electric Power**

**REQUEST**

Identify all costs incurred to date by AEP in connection with the development and membership in an RTO.

a. To the extent available, show separately the costs for: MISO the Alliance, and PJM.

b. Were all the costs expensed as they were incurred, or have any been deferred?
1. If any have been deferred, on whose books were they deferred?
2. What were the amounts of the deferrals?
3. Which regulatory agencies, if any, authorized the deferrals?

c. Does AEP intend to pass any of these costs to Kentucky Power in the future? If so, how much and when?

d. Does AEP anticipate that any of its RTO development costs will be reimbursed directly by PJM or through a charge assessed by PJM?

**RESPONSE**

(a) The costs incurred, as of December 31, 2002, exclusive of related carrying costs, by AEP in connection with MISO are $2,695,576 and the Alliance RTO (including Bridge Co.) are $7,767,948 ("Alliance Start-Up Costs"). To date AEP has incurred $3,494,803 ("PJM Integration Costs") to integrate the AEP System's transmission operations with PJM.

(b)

(1) Costs are being deferred on the books of the AEP east operating companies.

(2) The total deferral on the books of the AEP east operating companies is $15,241,380 inclusive of carrying costs.

(3) Requests to defer RTO formation/integration costs and related carrying costs have been granted by the Federal Energy Regulatory Commission (FERC) in Letter Orders issued by the FERC Chief Accountant to Duke Energy Corp., 94 FERC ¶ 61,080 (2001); Bangor Hydro-Elec. Co. Docket No. AC01-43-000 (May 11, 2001); Florida Power & Light Co., Docket No. AC01-23-000 (March 8, 2001); and Northeast Utilities, Docket No. AC02-6-000 (March 14, 2002). The Chief Accountant of the FERC, John Delaware, informed EEI member companies, including AEP, at an EEI/FERC Accounting Liaison meeting, that they could defer RTO formation/integration costs consistent with the above Letter Orders.

(c) AEP intends to seek recovery in future rate filings of all RTO formation/integration related costs, not reimbursed by PJM, plus any costs billed to KPCo in PJM's on-going administration fee, from those customers utilizing the AEP transmission system. KPCo's share of the costs shown in (a) above, inclusive of related carrying costs, as of December 31, 2002, is $950,040, which is deferred on KPCo's books.

(d) The rates proposed by PJM and the New PJM Companies in the "PJM Expansion Application" are intended to collect PJM start-up expenses for the New PJM Companies (Commonwealth Edison Company, Dayton Power & Light Company, Dominion Virginia Power and AEP), of approximately $13.6 million (inclusive of an estimated $10.1 million in PJM RTO integration costs over and above the approximately $3.5 million incurred through December 31, 2002) that the AEP Companies expect to be billed by PJM. The start-up costs are reflected proportionately in the Regional Through and Out Rate ("RTOR") and the zonal transition charges ("ZTA" and "TMEC").

**WITNESS:** J. Craig Baker

**Kentucky Power**
**d/b/a**
**American Electric Power**

**REQUEST**

Describe and quantify all of the revenue requirement impacts to Kentucky Power that will result from joining PJM. This response should include, but not be limited to, the following:

a. The difference between AEP's current transmission rates and its transmission rates as part of a PJM zone.

b. The change in rate of return on equity as proposed or requested in AEP's transmission tariff.

**RESPONSE**

(a) The effect on KPCo's revenue requirement, if any, of any difference between AEP's current transmission rates and its transmission rates as part of a PJM zone is expected to be minimal.

(b) The return on common equity in AEP's current transmission rate is unknown because the rate was the result of a settlement approved in a FERC order approving the merger of AEP and Central and South West Corporation. Also see the response to part (a) above.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

List each PJM rate that will be paid by or allocated or assessed to Kentucky Power. For each rate listed, provide the following information:

a. The specific service that will be offered or performed by PJM

b. The estimated annual costs to Kentucky Power.

c. An explanation of how Kentucky Power's estimated annual costs was calculated, including the billing determinants used in the calculation and whether it is calculated on a demand or energy basis.

d. The basis to be used for any allocation or assessment to Kentucky Power.

**RESPONSE**

Please refer to the PJM OATT.

a. The services offered by PJM are numerous, as revealed in the PJM OATT and the PJM Manual for Billing M - 29, which can be viewed at the following PJM website: http://pubs.pjm.com/dynaweb/PJMpubp.
AEP expects to receive all the services that a typical Load Serving Entity will require under the PJM OATT.

b. AEPSC, as agent for the AEP Companies, will be billed by PJM for the services the AEP Companies purchase and will be paid by PJM for the services the AEP Companies supply. AEPSC has not completed an analysis of all the costs the AEP Companies will be charged by PJM, but expects that Kentucky Power's portion of PJM Administrative charges (which may constitute the bulk of any net charges to the AEP Companies after credits for services rendered by the AEP Companies) will be approximately $3 million per year.

c. PJM estimates $45 million per year for Administration Charges per Schedule 9. The $45 million would be multiplied by KPCo's MLR, which averaged 7.3% in 2002, or approximately $3 million as estimated in part b above.

d. See responses to parts a, b and c.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Craig Baker's testimony, at page 8, mentions PJM's high required reserve margin as compared to that required in Each Central Area Reliability Council ("ECAR").

a. Provide a detailed explanation of the existing ECAR capacity reserve requirements and PJM's required reserve margin.

b. Explain the differences in AEP's reserve responsibilities under ECAR versus PJM.

c. Does Kentucky Power's reserve margin satisfy PJM's requirements in 2003 and in each of the following 10 years/ If no, explain the amount of the shortfall in each year and estimate the costs to Kentucky Power to meet PJM's requirements in each year.

**RESPONSE**

a. Currently, ECAR's daily operating reserve requirement is 4% of the same day forecast peak demand. Of that 4%, 1% is for regulation, which must be spinning, and 3% is for contingency reserve, half of which must be spinning.

Currently, PJM West has an available capacity requirement (ACAP) of 106% of the next day forecast peak demand. PJM utilizes the day-ahead nominated resources for ACAP to provide appropriate levels of spinning and contingency reserves to meet the ECAR Daily Operating Reserve requirements.

Alternatively, the PJM West load serving entities (LSE), in aggregate, in place of the ACAP requirement described above, may select an installed capacity (ICAP) requirement. ICAP is a seasonal obligation. PJM forecasts the period peak load (FPPL) for the season. Each PJM West LSE's effective ICAP requirement for the 2003 planning period is 112.1% of its FPPL.

b. AEP has estimated that in order to reliably maintain the 4% daily operating reserve required by ECAR, a planning reserve margin of about 12% is necessary.

c. Kentucky Power is one of the operating companies of the AEP System, which is planned, constructed and operated as a completely integrated electric power system. For the AEP System as a whole, it is necessary to establish and maintain sufficient generating-capacity resources to assure a reliable bulk power supply to the aggregate load of the combined AEP System operating companies. The evaluation of the adequacy and reliability of KPCo's generating capability to meet the current and projected power demands of its customers must be based on consideration of the total generating capability of the AEP System in relation to the aggregate AEP System load (taking into account contractual arrangements with non-affiliated parties).

At this time, a PJM ICAP requirement has not been determined beyond 2003. The AEP System's existing capacity should be sufficient to meet an effective 12.1% ICAP requirement.

With regard to sourcing for long-term capacity needs, if capacity remains plentiful in the region and is readily available at a relatively low cost, as at present in the ECAR area, then purchases of power in the market on an as-needed basis will result in the lowest cost. If however capacity is not plentiful in the region, or is available in the market only at very high or volatile costs, then AEP will have to consider construction of new capacity or the purchase of additional long-term capacity and energy, to provide adequate reliability while avoiding the risk of exposure to high market prices. Nevertheless, the Company does not believe that there will be any significant increase in cost associated with adhering to the current PJM ICAP reserve requirement as compared to the existing planning reserve requirements.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

## REQUEST

Mr. Baker's testimony, at page 10, asserts that the transfer of control is "consistent with the public interest" because "Kentucky Power's participation in PJM, as part of the integrated AEP System, will benefit Kentucky electric customers by improving the reliability and competitiveness of interstate wholesale energy markets, and greatly expand the generation sources economically available to Kentucky customers."

a. Provide all analyses that have been performed for Kentucky Power to support these conclusions.

b. Explain why AEP's membership in any RTO with which it has a direct interconnection would not improve the reliability and competitiveness of interstate wholesale energy markets, and greatly expand the generation sources economically available to Kentucky customers.

## RESPONSE

a. & b. See the response to Question No. 1. Also, with respect to increase in competition, with the proposed energy market in the expanded PJM region, the Kentucky Power customers will have access to about 153,000 MW of generation in the expanded PJM region while not paying out and through transmission charges linking such a vast generation pool to the AEP load.

AEP's participation in PJM will also improve the reliability of the AEP transmission system, especially in its southeast portion, which is experiencing relatively more congestion under certain system operating conditions as compared to the other part of the system. The congestion on AEP's southeast interface is, generally a result of facility outages and loading conditions on AEP's transmission in West Virginia and Virginia as well as the operation of the Allegheny Power and Virginia Power systems. Since these two systems will also be part of PJM, PJM will be better able to manage congestion in this region by internalizing needed redispatch and power flows, since the systems most affected – AEP, Virginia Power and Allegheny Power System are/or plan to be in PJM. This will help in improving the reliability of operation. The market-based generation redispatch to alleviate congestion will replace the existing TLR process and the non-firm and firm transactions should not be curtailed, thus improving the reliability of transactions.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

a. For each month of the last 3 calendar years, provide a schedule of revenues received by Kentucky Power from sales to non-associated companies.

b. Assuming AEP had been a member of PJM during the last 3 calendar years; provide an estimate of the monthly revenues that would have been received from sales to non-associated companies.

**RESPONSE**

a. See Question No. 10, Attachment 1 for a schedule of revenues received by KPCo from its member load ratio share of AEP system sales to non-associated companies by month for the last three years.

b. The Company has not performed any calculations to estimate what the monthly revenues from sales to non-associated companies would have been for the last three calendar years had KPCo been a member of the PJM RTO.

**WITNESS:** J. Craig Baker

AMERICAN ELECTRIC POWER
SCHEDULE OF REVENUES FROM NONASSOCIATED COMPANIES
JANUARY 2000 TO DECEMBER 2002

| MONTH | REVENUES Year 2000 | Year 2001 | Year 2002 |
|---|---|---|---|
| January | $ 1,368,483 | $1,572,319 | $1,197,344 |
| February | $ 1,447,679 | $877,653 | $752,540 |
| March | $ 647,553 | $2,807,283 | $1,031,274 |
| April | $ 1,578,668 | $4,453,206 | $1,662,867 |
| May | $ 3,333,653 | $4,411,744 | $301,164 |
| June | $ 2,667,492 | $1,684,319 | $3,489,678 |
| July | $ 4,995,371 | $6,782,672 | $1,426,832 |
| August | $ 7,682,554 | $3,144,284 | $715,253 |
| September | $ 2,286,323 | $308,161 | $2,311,209 |
| October | $ 1,566,740 | $517,025 | $1,976,175 |
| November | $ 1,592,205 | $471,920 | $1,814,515 |
| December | $ 5,717,103 | ($1,030,078) | $2,342,350 |
| **Total** | **$ 34,883,824** | **$26,000,508** | **$19,021,201** |

# Kentucky Power
# d/b/a
# American Electric Power

## REQUEST

a. For each month of the last 3 calendar years, provide a schedule showing Kentucky Power's costs for power purchased from non-associated companies.

b. Assuming that AEP had been a member of PJM during the last 3 calendar years, provide an estimate of what Kentucky Power's costs would have been for power purchased from non-associated companies.

## RESPONSE

a. See Question No. 11, Attachment 1, for a schedule showing KPCo's costs of power purchased from non-associated companies by month for the last 3 calendar years.

b. The Company has not performed any calculation which would estimate what KPCo's cost for power purchased from non-associated companies for the last three calendar years would have been had KPCo been a member of the PJM RTO.

WITNESS: J. Craig Baker

# AMERICAN ELECTRIC POWER
## SCHEDULE OF PURCHASED POWER FROM NONASSOCIATED COMPANIES
## JANUARY 2000 TO DECEMBER 2002

| | Purchased Power | | |
|---|---|---|---|
| Month | Year 2000 | Year 2001 | Year 2002 |
| January | $1,219,653 | $2,402,569 | $1,004,768 |
| February | $910,059 | $1,841,414 | $904,767 |
| March | $1,327,273 | $2,796,880 | $915,470 |
| April | $1,379,772 | $2,494,498 | $955,354 |
| May | $2,672,898 | $2,365,263 | $783,471 |
| June | $2,217,701 | $1,874,835 | $1,097,710 |
| July | $1,736,417 | $1,499,757 | $2,290,886 |
| August | $1,325,178 | $1,881,048 | $2,019,055 |
| September | $874,935 | $2,576,661 | $1,988,956 |
| October | $1,854,017 | $2,178,506 | $1,594,106 |
| November | $2,318,609 | $1,857,922 | $1,257,188 |
| December | $3,934,738 | $1,255,028 | $1,580,235 |
| **Total** | **$21,771,250** | **$25,024,381** | **$16,391,966** |

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

List each instance of unreliable service experienced by Kentucky Power's native load customers over the last 3 years that would not have occurred if AEP had been a member of PJM and explain how PJM membership would have eliminated or corrected each such instance.

**RESPONSE**

There have been no specific instances of unreliable transmission service in the Kentucky Power service area impacting the native load customers over the past three years. However, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the AEP System beyond acceptable limits that could have an impact upon the reliability to Kentucky customers. These outages involve the potential overload of the 345 kV circuit between the Kanawha River Station in West Virginia and the Matt Funk Station in Virginia. The outage of 765-kV transmission facilities, or neighbors' parallel 500 kV facilities (in Allegheny Power, Dominion Virginia Power and/or PJM systems), could result in thermal overloads and low voltages in the Kanawha River – Matt Funk area and on underlying transmission networks which will impact service reliability of AEP's native load customers in Kentucky. Allegheny Power is already part of PJM and Dominion Virginia Power is actively pursuing PJM membership. With AEP also part of the PJM RTO, potential overloads on the Kanawha – Matt Funk 345 kV circuit can be more effectively managed through PJM market operation, the security coordination, and NERC Transmission Loading Relief procedures. With AEP membership in PJM, service reliability to Kentucky Power's native load customers would be enhanced.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Quantify the anticipated improvement in reliability that will benefit Kentucky electric customers as a result of Kentucky Power's participation in PJM.

**RESPONSE**

See response to Question No. 9.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Identify the anticipated improvement in the competitiveness of the interstate wholesale energy markets as a result of Kentucky Power's participation in PJM.

**RESPONSE**

PJM has a state-of-the-art market in operation, including day-ahead and real-time energy, imbalance and ancillary service markets, and price discovery. The size of the existing energy and ancillary service markets in PJM will double as a result of the participation of the new companies as show in the following table. This will further improve the competitiveness of the interstate wholesale energy market. Access to such a vast pool of generation, without paying out and through transmission service charges, is expected to improve the competitiveness of the interstate wholesale market as result of AEP's participation in PJM.

**Table 1**

**Installed Generation and Peak Load in the Expanded PJM Region**

| PJM Zone | Installed Generation Capacity in MW | Peak Load in MW |
|---|---|---|
| Existing PJM and PJM West | 69,000 | 64,000 |
| American Electric Power | 29,000 | 21,000 |
| Commonwealth Edison | 32,000 | 22,000 |
| Dominion Virginia Power | 19,000 | 17,000 |
| Dayton Power and Light | 4,000 | 4,000 |
| Total For Expanded PJM | 153,000 | 128,000 |

**WITNESS:** J. Craig Baker

**Kentucky Power**
**d/b/a**
**American Electric Power**

**REQUEST**

Is AEP obligated either by agreement or order in other jurisdictions to join an RTO? If so, identify all agreements or orders, and the jurisdictions in which they were entered.

**RESPONSE**

Yes. The following regulatory commission orders, state laws and agreements impose such obligations:

a) Federal Energy Regulatory Commission, *American Electric Power Co. and Central and South West Corp,* Opinion No. 242, 90 FERC Par. 61,242 (2000).

b) Ohio Revised Code, Sections 4928.12 and 4928.34 (A) (13).

c) Virginia Code, Sections 56-577 and 56-579. Please note that Virginia Code Section 56-579 is subject to a proposed revision to the Virginia Code that would prohibit an incumbent electric utility from joining an RTO prior to July 1, 2004 but require joining an RTO by January 1, 2005.

d) Indiana Utility Regulatory Commission Order in Cause No. 41210, April 26, 1999, approving Stipulation and Settlement Agreement.

**WITNESS:** J. Craig Baker

**Kentucky Power**
**d/b/a**
**American Electric Power**

**REQUEST**

Explain whether Kentucky Power's retail customers will be charged PJM's costs to operate its real-time and day-ahead markets. If no, specify who will pay such costs.

**RESPONSE**

The costs to operate PJM's real-time and day-ahead markets are recovered through the FERC-approved PJM Administrative Fees listed in PJM's Open Access Transmission Tariff and will be charged to American Electric Power Service Corporation, as agent for its operating companies. Each operating company, including KPCo, will reflect their portion of these costs in their next retail base rate case.

**WITNESS:** J. Craig Baker

**Kentucky Power**
**d/b/a**
**American Electric Power**

**REQUEST**

For each of the services to be performed by PJM, identify any similar service that is currently being performed by AEP.

a. Will AEP continue to perform any of these services? If yes, identify all such services and explain whether this will result in any redundancy.

b. For those services that will be discontinued by AEP due to their being provided by PJM, explain how Kentucky Power's rates will be adjusted to reflect the elimination of AEP's costs of providing such services.

c. Describe the extent to which AEP's workforce will be reduced as a result of it transferring control of its transmission facilities to PJM.

**RESPONSE**

Presently AEP provides a substantial portion of the services required of a transmission owning utility under the FERC Pro-forma open access transmission tariff (OATT). Other services are performed under contract (See response to part. c. below). PJM offers all of those services under its OATT, and will provide those services for former AEP OATT Customers. In addition, PJM offers additional services that AEP does not offer today, including, among others, the operation of energy and ancillary service markets, congestion management based on its adoption of the locational marginal pricing (LMP) model, security constrained economic dispatch services, and regional transmission planning and capacity management services.

a. AEP will no longer provide those services directly to transmission customers, but AEP will supply energy, capacity and reactive power/voltage support services to PJM, in addition to providing PJM functional control of its transmission system to enable PJM to offer transmission service over the AEP transmission system.

b. AEP's charges for services provided to PJM will be collected through the PJM OATT. AEP's charges under the AEP OATT for such services will be eliminated.

c. AEP has already experienced workforce reductions in its central control center as a result of transferring administration of transmission request approval, and security coordination functions to the Southwest Power Pool (SPP), as a condition of the AEP-CSW merger. AEP does not anticipate significant additional workforce reductions in the immediate future as a result of transferring functional control of its transmission system to PJM; however, such efficiencies could result over time. AEP will continue to perform planning, scheduling, dispatching, operations and maintenance functions, as it does today, but under the direction of the PJM.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Under KRS 278.214, Kentucky customers have the highest priority use on transmission facilities.

a. Explain whether this transmission priority will continue with membership in PJM.

b. Provide assurance that PJM's method for allocating Congestion Revenue Rights/Financial Transmission Rights ("CRRs/FTRs") is adequate to protect this transmission priority for Kentucky customers.

**RESPONSE**

a. See Question No. 18, Attachment 1, which is a filing by Kentucky Power in Case No. 2002-349. AEP's participation in PJM should not change any of the matters discussed in the filing, except that the LMP congestion management system is designed to reduce reliance on transmission loading relief (TLR) for relief of transmission congestion.

b. The congestion revenue rights/financial transmission rights distributed by PJM are strictly financial rights and are meant for hedging potential congestion costs and not to change transmission priority. PJM will also be the Reliability Coordinator for the AEP East transmission on behalf of NERC. PJM will operate the AEP system in the interconnected network environment according to the PJM Operation Agreement while adhering to the NERC reliability requirements. These requirements will not change as part of AEP's participation in PJM.

**WITNESS:** J. Craig Baker

# COMPARISON OF SMD TO PJM

## MUCH OF THE FUNDAMENTAL DESIGN OF SMD IS CONSISTENT WITH CURRENT PJM MARKET

- LMP based (for all nodes); ex post pricing
- CRRs = FTRs = Financial Transmission Rights
- All entities pay LMP-based Clearing Price
- Single Market Operator and System Operator
- Bid-based economic dispatch is basis for Day-ahead and Real-time Markets
- Voluntary generation unit commitment and dispatch
- Bilateral plus spot markets

## CONGESTION REVENUE RIGHTS MODEL

***Consistent with PJM Market Design*:**

- Property rights are allocated to customers who pay transmission access charges
    - Initially assigned to long-term firm customers, consistent with the existing pro forma tariff's right of first refusal; short-term and non-firm point-to-point customers would not receive CRRs.
- Provides for long-term CRR Auctions
- Encourages development of new hedging alternatives (i.e., PTP CRR Options)
- CRRs hedge against congestion charges
    - Acquire CRRs for receipt / delivery point(s)
    - Entitle holder to revenues from congestion between designated points to offset customer's congestion costs
    - If holder opts not to schedule service, still receive congestion revenue (i.e., the price differential between the receipt and delivery points).

***Different from PJM Market Design***:

- Proposes Transmission Owner funding of CRR revenue shortfall (see below)
- Transmission scheduling priority for CRR holders (see below)

| [redacted] | [redacted] |
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| SMD proposes that CRRs holders have a physical transmission scheduling priority. (159, 243)<br>Under the proposed rule, if there is a day-ahead or real-time transmission constraint that cannot be resolved, transactions without CRRs would be curtailed first. | FTRs are a financial congestion hedging mechanism, and they provide no physical transmission scheduling priority. Scheduling priority is based on whether the transmission customer has firm or non-firm transmission service.<br><br>Curtailment, if required, would occur pursuant to Transmission Loading Relief procedures. In real time transactions are curtailed by transmission priority (lowest priority non-firm up to highest priority firm). |
| The SMD proposes that the Transmission Owners will be responsible to cover the shortfall in congestion revenue that must be redistributed to CRR holders. (751) | PJM equally decreases the value of the FTRS if PJM does not collect 100% of the congestion revenue needed to cover all the FTRs. FTRs do not always provide a 100% hedge. |

# DAY-AHEAD ENERGY MARKET

| [redacted] | [redacted] |
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| ➢ Voluntary Participation (269) – The NOPR proposes completely voluntary participation by both buyers and sellers in the Day-ahead Market while at the same time allowing both supply and demand to submit price-insensitive offers/bids. | PJM energy markets are voluntary in the sense that generation/load may choose to self-supply, enter into a bilateral transaction, or use the energy markets. However, generation resources that are designated as PJM Capacity Resources <u>must</u> bid into the Day-ahead market unless they are self-scheduled or unavailable because of an outage. Units that bid into PJM's Day-ahead market or self-schedule are dispatchable by PJM in real time. |
| ➢ The NOPR allows market participants to buy | PJM allows "up to" congestion bids but places a $25 cap on the |

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| through transmission constraints (i.e., they pay congestion charges in lieu of curtailment). (210) The NOPR does not place a limit on the maximum amount of the "up to" bid. The NOPR also does not place a limit on the possible sources/sinks that may be included in such transactions. | amount of congestion that a party may include in the bid. For example, a party may bid 100 MW to go from X source to Y sink if the price difference between those two points does not exceed $25.<br><br>PJM does not place restrictions on the source and sink of such transactions, but it does prevent parties who acquired FTRs in the monthly FTR auction from profiting from their FTR position in the Day-ahead market (Otherwise, the party holding the FTR could cause congestion in the Day-ahead market with even just a few MWs depending on the source/sink path and then inc or dec and extract additional value for its FTR.) |
| The NOPR proposes the following additional features to increase market flexibility for the Day-ahead and Real-time market (307):<br><br>– Multi-hour block bids for transactions going in or out of PJM<br>– Multi-hour block demand bids (259) (i.e., the load submits a multi-hour block bid indicating a maximum price for the entire multi-hour period)<br>– Multi-part demand bids (272) (i.e., that indicate time and price constraints under which buyers are willing to purchase energy)<br>– Day-ahead Ancillary Services Markets (284) (Regulation, Spinning and Supplemental) | PJM allows generators to submit multi-part and multi-hour sell offers for generators and demand-response participants correlated to physical limitations of the generation units and load themselves (i.e., start up, no load, minimum run for generators, and minimum down times for demand response loads).<br><br>PJM does not have day-ahead ancillary service markets. |
| [redacted] | [redacted] |
| Regulation – The NOPR proposes to require financially binding Day-ahead Regulation Market. (284) | PJM has only a real-time Regulation market. |

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| Spinning and Supplemental Reserves - The NOPR proposes to require a Day-ahead, financially binding Spinning and Supplemental Reserve Market. (284) | PJM does not have Real-time or Day-ahead spinning or supplemental reserve markets. PJM is working to implement a Real-time Spinning Market for December 1, 2002. |
| ➢ Real-time Ancillary Services Availability Bids (322) - The NOPR proposes to eliminate availability bids(i.e., offers indicating the price at which a generator is willing to be available to provide this service) for real-time spinning reserve services. It asserts that the types of costs reflected in availability bids are incurred only in the day-ahead time frame, not in real time. | PJM does not have a Real-time spinning market but does pay synchronous condensers for the costs they incur (i.e., O&M) to provide this service. |
| [redacted] | [redacted] |
| ➢ Hourly Changes to Generator Offer Prices in Energy Market (273,307) – The NOPR proposes to permit generators to submit new offer curves every hour. (Offer curves indicate how many MWhrs the generator is willing to provide at what price.)<br><br>➢ In addition, the NOPR proposes flexible transaction scheduling rules (i.e., rules for sales into and out of PJM) and self-scheduling of generation. | PJM's Day-ahead Market is based on scheduled hourly quantities and day-ahead hourly prices. The generator's bid covers all 24 hours in the day and is submitted prior to the operating day; the generator does not submit separate bids for each hour.<br><br>PJM's current market rules allow self-scheduled generators to change their schedules with only 20 minutes notice. |
| ➢ Incremental and Decremental offers / Bids in Energy Market(307) - The NOPR proposes that the Bids and Offers submitted in the Real-time Market be in the form of incremental and decremental adjustments to the Day-ahead market position for each load and generator. In other words, the NOPR appears to require a generator to offer the price the generator wishes to receive for the deviation. | PJM currently accepts Real-time offers in exactly the same form as was submitted in the Day-ahead market. (PJM uses incremental cost curves) Offers are not submitted for the incremental or decremental adjustment alone. |

| [redacted] | [redacted] |
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| The SMD proposes to eliminate the <u>forward</u> physical transmission reservation system for managing external transactions. (152-153) All transmission service will fall under the Network Access Transmission Service (see below, "Transmission Service and Pricing" section). Transmission service, therefore, is not scheduled on a physical basis but rather a financial basis. | PJM schedules forward transmission service for external transactions using OASIS. |

# MARKET MONITORING

## THE FUNDAMENTALS OF SMD'S APPROACH TO MARKET MONITORING ARE CONSISTENT WITH CURRENT PJM MARKET MONITORING

- **Mitigation of local market power using ex ante offer caps based on generator cost.**
- **Safety net bid cap at $1,000/MWh**
- **Capacity/Adequacy construct (although the NOPR's construct differs from PJM's construct)**
- **Optional backstop measure for significant market issues (aggregate Automated Mitigation Procedure) (Although PJM does not presently use this approach, this is not inconsistent with PJM's practice.)**

**Consistent with PJM approach:**

- Autonomous of market participants
- Report to FERC and to independent RTO Board
- Defined monitoring of ISO

**Inconsistent with PJM Approach:**

- Autonomous of ITP management
- Administer system of specific penalties

| [redacted] | [redacted] |
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| <u>Local Market Power Mitigation</u><br>➢ The NOPR states that mitigation must rely on must-offer obligations to mitigate physical withholding and bid caps to mitigate economic withholding (i.e., where the unit is the unit that would alleviate a local transmission constraint, or a "must-run" unit). (418)<br>➢ The "must-run" designation is not linked to the unit being designated as a Capacity Resource.<br>➢ The NOPR establishes an offer cap for such must-run units based on the unit's marginal cost plus an adder. (419-421)<br>➢ The NOPR addresses opportunity costs for energy-limited resources in determining the cap. (422-423)<br>➢ Mitigation would apply to both day-ahead and real-time markets.(424) | PJM's rules are consistent with the NOPR except for the proposed treatment of bilaterals to substitute for market power mitigation. |
| The NOPR addresses options for dealing with the risk of a forced outage of a unit in a load pocket: (412)<br>➢ A portion of available day-ahead capacity may be exempt from the bid-in requirement to reflect forced outage risk in real time.<br>➢ Allow generators to provide all available capacity in real time at a capped bid in lieu of bidding in the day-ahead market to accommodate generators that have significant risk or opportunity costs.<br>➢ If the generator receives a capacity payment, that payment compensates for the forced outage risk so that the generator should be obligated to deliver energy or to pay for substitute supply from another source. If the generator does not | PJM requires the generation owner of a must-run unit to replace the energy in real time if the unit does not run. The capacity market rules provide an incentive to run because the value of capacity declines as the forced outage rate of the unit increases. (The capacity value of the unit takes into consideration the forced outage rate of the unit.) |

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| receive a capacity payment, then it should not have to bear the risk of a legitimate outage. | |
| The NOPR proposes to exempt sellers who control a small amount of capacity in the market (e.g., no more than 50 MW) from mitigation. (428) | PJM's rules provide no exemptions. |
| The NOPR proposes a series of minimum behavioral rules which would be monitored by the market monitor. (445) These rules would be accompanied by predetermined penalties. (446, 455) | PJM's rules contain no such penalties. |
| The NOPR establishes a safety net bid cap of $1000. Imports would be allowed to set the market clearing price up to the capped value. The market monitor may exempt units from the cap. (413) | ➢ PJM has a bid cap of $1000.<br>➢ Internal and external resources are treated identically in PJM . Both internal and external resources can offer energy in the day ahead market that can set the price both in the day ahead and real time markets. Neither internal nor external resources can change their offers in real time. Both internal and external resources are price takers in real time if they have not made a specific price offer during the day ahead market or during the reliability run on the day ahead of the operating day.<br>➢ The market monitor cannot exempt any unit from the bid cap. |
| [redacted] | [redacted] |
| Reserve Requirement set by Regional State Advisory Committee | PJM does the administrative analysis to determine an appropriate Reserve Margin level. The PJM Board approves the Reserve Margin level, and then PJM translates that into an obligation for each LSE according to the share of the PJM load they serve. |
| Minimum Reserve Requirement of 12% (installed capacity) over forecast peak | PJM does not have a minimum Reserve Requirement. Rather, PJM's Reserve Margin is set at a level calculated to achieve a loss of |

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| | load probability of no greater than one day in ten years. |
| Planning horizon is determined by region. NOPR discusses establishing requirement for period of three to five years into the future to promote the development of new generating resources and their ability to contribute to the satisfaction of LSE obligations. | PJM evaluates needed reserve levels over the next five years and sets the Reserve Margin based on a calculation that looks one year ahead based on the most recent forecasts of load and resources, among other factors. The market signals sent through the energy market and the five year projection of required reserves appear to have been sufficient to promote a significant level of generation development in PJM. |
| ➢ Loads must provide for allocated share of required resources.<br><br>➢ Loads must submit plans to meet resource needs of area, plans may include: (533, 536)<br>• generation with necessary transmission capability for delivery<br>• bilateral contracts backed by specific generating units (with transmission) with deliverability<br>• demand response with deliverability<br>➢ The NOPR suggests a point-to-point deliverability test, with each LSE being required to show that its capacity resources are deliverable to its load. (511, 514)<br><br>➢ Plans are audited by ITP<br><br>➢ No discussion of shifting of load responsibility related to retail access programs (or for any other reason) | ➢ PJM requires LSEs to meet a capacity obligation based on their share of the PJM load.<br><br>➢ We permit LSEs to satisfy their capacity obligations using their own generation resources, Active Load Management (technically, ALM reduces their obligation), bilateral contracts, or the PJM capacity credit markets (daily, monthly and multi-monthly markets).<br><br>➢ Resources used to satisfy obligations are committed to PJM. Commitment of resources and on-going resource performance is tracked by PJM.<br><br>➢ Similarity between NOPR and PJM's structure:<br>o The NOPR talks about resources being used to meeting capacity adequacy requirements of only one region (would need to be deliverable to that region and would be recallable to that region). PJM's current structure allows resources to determine which region it wishes to serve as a capacity resource, and once they decide to commit to PJM, they are recallable to PJM.<br><br>➢ PJM requires the resources that LSEs use to meet their capacity obligations to be deliverable to PJM. PJM's concept of |

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| | deliverability is a network deliverability concept, not that a particular resource is deliverable to a particular point in PJM. PJM dispatches the entire system to serve the load using network transmission service.<br><br>➢ PJM's structure specifically accommodates retail choice. The LSEs' capacity obligations are accounted for on a daily basis to allow for load responsibility to shift through retail access programs. A series of markets are operated by PJM to help facilitate the ability of load serving entities to satisfy their capacity obligations (in addition to the LSEs being able to use owned generation or bilateral contracts to meet their capacity obligations). PJM's capacity credit markets include daily, monthly and multi-monthly capacity markets. |
| ➢ Penalties are imposed on an LSE that did not satisfy the requirement to submit a plan (at the start of the planning horizon) with sufficient resources to meet it's obligation when the region is short of operating reserves (during the operating day) and that load serving entity is taking energy from the spot market.<br><br>➢ Penalty amounts start at $500 per MWh if an area is 1% short of operating reserve, $600 for 2%, etc.<br><br>Parties not providing reserves (and taking energy from the spot market) must be shed first if the region needs to shed load, if not possible they pay a $1,000 per MWh penalty. State regulators also notified of the party's failure to provide adequate resources. | How PJM LSEs meet their capacity obligations is much different than what the NOPR proposes, so the penalty structure currently in place in PJM for LSEs that fail to meet their obligation, is not comparable to the penalty structure proposed by the NOPR. The penalties that PJM has in place under its current capacity adequacy structure are significant and provide a strong incentive for LSEs to provide capacity to PJM control. |
| NOPR is ambiguous as to whether need the same capacity adequacy structure for all regions or whether there may be regional differences. | |

| [redacted] | [redacted] |
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| ➢ The NOPR proposes the implementation of regional planning processes across defined planning areas. PJM, MISO, and SPP are one such defined planning area. The NOPR requires that a regional plan be completed for each planning area within twelve months of the effective date of the order. (590) | ➢ PJM has a regional planning process that currently includes PJM and PJM West. The Joint and Common Market with the MISO and SPP will include regional planning across the MISO-PJM-SPP footprint. |
| ➢ The NOPR, in separate paragraphs, requires that the regional planning process identify beneficial transmission needed for reliability and economics and requires that the process should identify reliability and economic needs, leaving open the question of how and by whom those needs should be met. (473, 503) Following the identification of needs, the ITP will conduct an RFP process to solicit solution alternatives and then evaluate submitted proposals. If the RFP is unsuccessful, the ITP may then order transmission solutions that would be the responsibility of the affected transmission owner. | ➢ PJM conducts a fully integrated planning process. The process establishes a base-line system that is compliant with reliability criteria and preserves all existing long-term firm rights regarding access to the transmission system. PJM then evaluates market driven needs, such as generation interconnections, and identifies transmission system enhancements required to accommodate such market needs consistent with reliability criteria. Cost responsibility for transmission system upgrades is assigned on a cost causation basis. [The baseline establishes a starting point for analysis of market driven needs and cost allocation for required system upgrades.] |
| ➢ For regions with ITPs, the NOPR adopts participant funding (i.e., those who benefit from a particular project, such as a generator building to export power or load building to reduce congestion) pay costs of construction and receive CRRs.<br><br>➢ For regions without ITPs, the NOPR proposes that all costs associated with transmission projects are rolled in on a region-wide basis. | ➢ Cost responsibility for transmission system upgrades is assigned on a cost causation basis. |

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| ➢ FERC states that Multi-State Entities could be an important component of the regional planning process. (474, 491, 524, 553) | ➢ Currently, the states are included in PJM's regional planning process. The PJM RTEPP is an open stakeholder process.<br><br>➢ Pursuant to the MOU between the PJM Board and the MACRUC member state public utility commissions, the states may communicate with the PJM Board of Managers, which approves the Regional Transmission Expansion Plan. |
| [redacted] | [redacted] |
| ➢ NOPR said that if CBM is going to be used, it must be used comparably and those who use it should compensate fairly for that use (i.e., any mechanism that allows for the use of this capability must apply equally to all) What is not clear is how tie capability will be utilized under SMD. If CRRs determine the priority of use of tie capability, then CRRs would need to be secured to use external generation to satisfy the capacity obligation. Perhaps CRRs could be utilized to preserve the benefits currently derived through CBM. | PJM includes the statistically determined capacity value of the transmission capability represented by CBM in the determination of the Installed Capacity Reserve Requirement. The requirement is less than it would be if that benefit were not considered and LSE's, therefore, are required to provide a slightly smaller amount of generating capacity to satisfy their obligations (currently 117% vs 120% of peak load). PJM withholds the transmission capacity associated with CBM from firm ATC in order to ensure the ability of PJM to utilize available generating capacity from neighboring systems during a PJM emergency. |
| [redacted] | [redacted] |
| ➢ The NOPR creates a single transmission service for all customers (bundled retail and unbundled and wholesale). (136) This service is called Network Access Transmission Service. Transmission service is available to any customer up to the full amount of the transfer capability, so long as the customer is willing to pay the applicable congestion charges. 140, 146) All accepted transactions must be physically feasible under a security-constrained system dispatch. (140) This service eliminates the distinctions between firm and non-firm by making all services firm, subject to the customer paying the cost of congestion (with CRRs as a financial hedge | ➢ PJM offers both Network Integration Transmission Service (NITS) and Point-to-Point Transmission Service. Load Serving Entities primarily use (NITS). PJM ensures that all accepted transactions are physically feasible. NITS limits the customer's use of this service to the amount of network load that customer has. Receipt and delivery points under NITS include individual nodes, zones, and trading hubs. |

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| to that congestion). (144) | |
| ➢ Embedded transmission cost would be recovered through an access charge for Network Access Service on all LSEs based on their respective shares of the system's peak load. (142, 169). FERC accepts license plate rates but inquires as to whether this should be just for a transition period with later movement to full postage stamp rates. FERC inquires as to whether rate methodologies can vary between RTOs based on recommendations of state advisory councils. FERC also seeks comments on whether bundled load should pay some transmission rate upon implementation of SMD or after a four year transition. (178) | ➢ Transmission Owners recover their revenue requirement through license plate rates and from receipt of an allocated portion of through and out revenues. Rates consist of both network and point to point transmission service.<br><br>➢ PJM recently sought to extend license plate rates in PJM West to match review of PJM East rate pricing. (PJM extended the license plate rate structure which was to expire in 2004 when PJM was to go to a system-wide rate.) |
| ➢ FERC's proposal is intended to eliminate rate pancaking between and within ISOs. (170) FERC proposes two methods for comment:<br>o Exporting region allocates a portion of its revenue requirement to importing region with all of the importing region's customers paying an uplift charge whether or not they import. (186)<br>o Importing region's transactions assessed an inter-regional charge to compensate exporting region's transmission owners. (187)<br><br>➢ Charges would then be assessed within the RTO by zone to assign costs to the zone within the RTO actually importing.<br><br>➢ FERC invites additional pricing proposals from the Regional State Advisory Councils. | ➢ All rate pancaking within the "PJM East" region was eliminated at the inception of PJM energy markets. The rate pancaking between "PJM East" and "PJM West" was eliminated at the start of PJM West markets with Allegheny's lost revenues being recovered by being netted against administrative cost savings to all PJM users.<br><br>➢ PJM charges a "through and out" rate for exports and wheel through transactions. (There is no charge for imports. Loads just pay for network transmission service.)<br><br>➢ FTRs are only assignable within the PJM/PJM West regions. FTRs do not go beyond PJM/PJM West into other Control Areas. They are, however, assigned within PJM/PJM West to those who pay for transmission system upgrades. |

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| ➢ CRRs would be assigned across RTOs, for example, by paying a portion of MISO Transmission Owners' revenue requirements, PJM load would be entitled to a proportionate share of MISO's CRRs. (189) | |

| GOVERNANCE | |
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| [redacted] | [redacted] |
| ITP Board is accountable to FERC, not the market participants; it should ensure: system reliability and operating efficiency, efficiently functioning markets, and short and long-term planning objectives. (558) | Board's primary responsibilities are to ensure: (1) the safe and reliable operation of the Interconnection, (2) the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Control Area, and (3) the principle that a Member or a group of Members shall not have undue influence over the operation of the Interconnection. |
| Stakeholder committees must be advisory, rather than function as a decision making body. (560) | Members Committee is not only advisory, but also can amend provisions of the Operating Agreement including energy market rules. |
| Requires six stakeholder classes: (1) generators and marketers, (2) transmission owners, (3) transmission-dependent utilities, (4) public interest groups, (5) alternative energy providers, and (6) end-users and retail energy providers. (561) | Members Committee is composed of five sectors: (1) generation owners (2) other suppliers, (3) transmission owners, (4) electric distributors, and (5) end-use customers. |

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| No specific Member voting protocol is identified. | 2/3 affirmative vote of Members, on a sector basis, is required for an action |
| Separate Regional State Advisory Committee advises the Board. (561) | Memorandum of Understanding with MACRUC regulatory commissions establishing liaison to the Board. |
| **Board Qualifications** | |
| NOPR proposes ITP Board of Directors of between 5 and 9 members. (562) | PJM has 8 Board members with its President as a non-voting Board member. |
| Qualifications in one or more fields: senior corporate leadership of a major publicly traded company; professional disciplines of finance, accounting, or law; electrical engineering; regulation of utilities; transmission system operations or planning; trading or risk management; information technology; and generation planning operation. (563) | Qualifications in fields of: corporate leadership at the senior management or board level; professional disciplines of finance or accounting, engineering, or utility laws and regulation; experience with concerns of transmission dependent utilities; experience in operation or planning of transmission systems; experience in commercial markets and trading and associated risk management. |
| No current or recent ties (two years) with market participants; divestiture of interests within six months. (564) | No ties with market participants for five years; divestiture of interests within six months |
| Annual financial disclosure Statements, available for audit by FERC. (564) | Annual certification of no direct financial interests. |
| **Selection of the Board** | |
| Nationally recognized search firm, retained by a Nominating Committee, supplies at least two names for each vacancy. (565) | Office of Interconnection retains search firm; no specific requirement to identify two candidates per vacancy. |

| | |
|---|---|
| Nominating Committee composed of two members from each sector votes, by simple majority, to fill Board vacancies individually; FERC seeks comment on whether the Nominating Committee should vote on an entire slate rather than on individual candidates. (566-568) | Members Committee votes to fill Board vacancies by a two-thirds sector vote; nominating committee of the Board presents a slate to Members Committee, which votes on the entire slate. |
| FERC seeks comments whether CEO should be a non-voting member of the Board. (567) | President is a non-voting member of the Board. |
| Terms: staggered four year terms; term limit of two consecutive terms. (570) | Staggered three-year terms; no term limits. |
| **Board Succession** | |
| If an existing Board member wishes to serve a second term, stakeholders vote to determine whether the Board member does so. If vacancies remain, Nominating Committee process is followed. (572) | No separately specified process for existing Board members; part of normal election process. |
| Resignations and removal for cause: search firm identifies candidates; Nominating Committee "review[s] the list of candidates and propose[s] new board members" (571) | Vacancies between Annual Meetings are filled by vote of remaining Board members. |

| | |
|---|---|
| **Other Matters** | |
| ➢ Communications between Members and the Board.<br>o No provisions in the SMD NOPR aside from establishment of stakeholder advisory committee. | ➢ PJM Board members attend the Members Committee and other committee meetings.<br>➢ PJM Board also communicates with members through the Liaison Committee.<br>➢ The Operating Agreement allows Members (minimum of 5) to create a user group to bring an issue directly to the Board.<br>➢ Ex Parte Member communications with the PJM Board are posted on the PJM web site. |

# INDEPENDENT TRANSMISSION COMPANIES

## FERC's position on the overall role of ITCs:

In the Translink Order, FERC indicated that an ITC can perform various functions "within its footprint" but indicated that functions such as planning and congestion management must be coordinated with the RTO. FERC's order made it clear that the split of functions would need to be reexamined once there is an integrated marketplace as anticipated in SMD. In the SMD Order, FERC praises the role of ITCs and seeks to revisit the Translink Order. It is not clear if FERC's SMD Order seeks to expand or limit which functions the ITC can undertake exclusively as compared to the RTO.

## PJM:

FERC issued an order, Alliance Companies, et al., 100 FERC P. 61,137 (2002) requiring PJM to file tariff amendments to address ITCs. On January 10, 2003 PJM filed two new attachments, pursuant to this order, to amend the PJM OATT and set forth the terms and conditions for ITCs to operate in the PJM region. This filing is pending approval by the FERC, and an effective date of March 12, 2003 is proposed for the changes.

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

In AEP's comments to Federal Energy Regulatory Commission ("FERC") regarding the Notice of Proposed Rulemaking on Standard Market DEsign, AEP expresses concerns about PJM's method of allocating CRRs or FTRs, as follows:

> Similar problems arise with the use of CRRs to hedge congestion costs because the NOPR fails to ensure that LSEs will have the same level of service flexibility that they enjoy today to serve their native load.... However, once the CRR process is implemented, LSEs may be required well in advance (for instance, one year) to choose generation-to-load paths of service that will result in an award of CRRs (or the revenue from CRR auctions) based on these path choices, and the LSEs may be locked into these choices for a set period of time. we are concerned that flows on the system are dynamic and a static set of CRRs may not provide full congestion protection. (See AEP comments at page 4, filed November 15, 2002 RM01-12-000.)

How does PJM's method of allocating CRRs or FTRs alleviate AEP's expressed concerns?

**RESPONSE**

In the SMD comments, AEP stated that.. . "The use of CRRs, whether they are allocated or auctioned, could, *if improperly designed*, leave LSEs open to significant cost exposure due to additional congestion costs to serve their native load" (emphasis added). AEP's concerns regarding the FERC SMD NOPR referred to in this Question were focused upon the mismatch that may occur between actual congestion costs derived from the real time dynamic power flows and a prescribed static allocation of FTRs based on an annual process of specific resource and load designations. Even though, FTRs or CRRs hedge congestion costs on a day-ahead basis and for particular paths from resource to load, the operation of the power system in real-time could potentially leave native load unhedged for either difference between day-ahead and real-time flows or for paths that FTRs have not been allocated.

AEP is currently working with PJM through the stakeholder process to alleviate much of the concerns expressed in its SMD NOPR comments regarding this issue. Possible options being discussed to mitigate such concerns include: 1) the implementation of a single load zone that would mitigate the effects of congestion risk by internalizing this risk as much as possible, 2) allocation instead of auction of FTRs for a longer period until the dynamic flows of the expanded PJM are better understood, 3) the implementation of a monthly and weekly markets for FTRs that would enable trading of rights with the intent of providing residual auctions in the future as close to real time as possible, and 4) allocation of all FTRs required serving native load and firm requirements.

AEP believes that a properly designed process of distribution of FTRs should minimize, if not eliminate, any potential exposure to unhedged congestion costs. Currently, PJM has agreed to allocate FTRs to AEP at least for one year.

**WITNESS:** J. Craig Baker

**Kentucky Power**
**d/b/a**
**American Electric Power**

**REQUEST**

What rate of return on equity has AEP proposed or requested to be utilized in its transmission tariff?

**RESPONSE**

13.0% plus a 50 basis point adder for RTO participation. See also the response to Question No. 6.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

a. Does Kentucky Power anticipate any loss of revenues due to the elimination of rate pancaking in its region? If yes, estimate the amount for 2003 and for each of the next 10 years.

b. Describe any measures to be taken by PJM to make up for those lost revenues and the number of years that those measures will remain in place.

c. Explain how Kentucky Power will address any loss of revenue due to the elimination of rate pancaking.

**RESPONSE**

a. The rates incorporated in the December 11, 2002 PJM OATT filing apply during a Transition Period ending January 31, 2005, and are designed to be revenue neutral as to the through and out transmission service revenues collected by the PJM RTO participants during the test year 2001. No analysis has been prepared to estimate the revenues that might result after the test year if the proposed rates are approved. The rates, which might apply after the Transition Period, are not known.

b. See response to a.

c. AEP will address this issue when the Post-Transition PJM rate design, crafted pursuant to the PJM Transmission Owner and Stakeholder processes and FERC SMD policy, is more clearly known.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

## REQUEST

In Mr. Baker's testimony, at page 12, he states, "Among the conditions imposed by FERC on AEP's choice of PJM is the requirement that North American Electric Reliability Council ("NERC") must approve PJM and MISO's updated reliability plans." Either provide documentation of NERC's approval or explain the status of the approval process.

## RESPONSE

On November 5, 2002, NERC submitted an initial report to the FERC on the PJM and Midwest ISO Reliability Plan. NERC reported that it approved the first phase PJM and Midwest ISO expansions, concerning changes in the geographic boundaries of the respective regions for which PJM and the Midwest ISO serve as the regional reliability coordinator. Therefore, NERC has approved the PJM expansion plan necessary for AEP and ComEd to transfer functional control of their transmission facilities to PJM, until the start of expanded PJM market operations. Pursuant to NERC approval, PJM assumed the role of Reliability Coordinator for the AEP, ComEd, Dayton Power and Light, and Duquesne Light electrical systems. Reliability coordination plans for market integration are under development. The market integration plan will address how congestion between PJM and MISO will be handled prior to the Common Market, and after the Common Market is developed.
PJM plans to present to NERC an updated reliability coordination plan that includes a congestion management proposal. This plan fully addresses any reliability and operational concerns associated with loop flows during the period that PJM (including AEP) is under the LMP-based market and the Midwest ISO has not yet established a market or is under a separate market.
MISO and PJM are working together and will present implementation plans for the congestion management solutions for Regional and NERC endorsement in March 2003. In April 2003 MISO and PJM will conduct training, tests, and drills of the congestion management solutions, and in May 2003 the PISO/PJM congestion management tools will be implemented. PJM/MISO will improve upon the processes when areas for improvement are identified. A joint operating agreement between PJM and MISO will be filed with the FERC prior to commencement of market operations.

The details of the MISO-PJM reliability plan review is included as Question No. 22, Attachment 1. Further information and documentation related to approving the revised Reliability Plans of MISO and PJM including FERC orders and filings, can be obtained from the NERC website at http://www.nerc.com/~filez/miso-pjm.html.

**WITNESS**: J. Craig Baker

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

# MISO/PJM Reliability Plan Review Team Meeting

February 12, 2003 — 8 a.m.–noon

The Ritz Carlton Phoenix
2401 E. Camelback Road
Phoenix, AZ 85106
Phone: 602-468-0700 — Fax: 602-468-0793

## Agenda

1. **Administrative**
   a. Arrangements
   b. Determination of Quorum
   c. Review of Agenda and Conduct of Meeting
   d. Parliamentary Procedures
   e. Antitrust Compliance Guidelines
   f. Review and Approval of Meeting Minutes
      i) January 21, 2003 MISO/PJM Reliability Plan Review Team Meeting
   g. Future Meetings

2. **MISO/PJM Review Team Documentation**

3. **Discussion of MISO/PJM Day 2 Congestion Management Issues**
   ✓ **Summary of Issues Identified by the Review Team**
   a. PJM's Proposed Market Flow Calculation
   b. Transmission Allocation
   c. Control Area/Control Zone Responsibilities
   d. Tagging In/Out/Across Markets
   e. Selection/Creation of Market/TLR Coordination Flowgates
   f. IDC versus LMP Calculation of Flowgate Impacts
   g. Generation-to-Load Distribution Factor (GLDF) Calculation
   h. ATC/AFC Calculation and Consideration of External Flowgates
   i. Timing of Hold Harmless Settlement Discussions
   j. Contingency Plans to Proposed Implementation

   ✓ **Summary of Issues Identified by the Operating Committee**

4. **Policy Review Task Force Report**

**All documents related to approving the revised Reliability Plans of MISO and PJM, including FERC orders and filings, are posted at: http://www.nerc.com/~filez/miso-pjm.html**

## Item 1. Administrative

a. Arrangements
b. Determination of Quorum
c. Review of Agenda and Conduct of Meeting
d. Parliamentary Procedures
e. Antitrust Compliance Guidelines
f. Review and Approval of Meeting Minutes
   i) January 21, 2003 MISO/PJM Reliability Plan Review Team Meeting
g. Future Meetings

### *Item 1.a Arrangements*

Review Team secretary Larry Kezele will review the meeting arrangements.

### *Item 1.b Determination of Quorum*

The secretary will announce whether a quorum (one-half of the voting members) is in place. NOTE: The Review Team cannot conduct business without a quorum. Please be prepared to stay for the entire meeting.

### *Item 1.c Review of Agenda and Conduct of Meeting*

Review Team chair Mark Fidrych will review the agenda and note changes as necessary. The primary purpose of this meeting is for MISO and PJM to provide an overview of their proposed seams congestion management process.

### *Item 1.d Parliamentary Procedures*

A summary of Parliamentary Procedures is attached for reference. The secretary will answer questions regarding these procedures.

**Attachment**

Parliamentary Procedures

### *Item 1.e Antitrust Compliance Guidelines*

The NERC Board of Trustees at its June 14, 2002 meeting adopted the NERC Antitrust Compliance Guidelines. The Board also instructed that these Guidelines be included in the agenda package for each meeting of every NERC committee, subgroup, or other NERC-sponsored activity.

**Attachment**

Antitrust Compliance Guidelines

### *Item 1.f Review and Approval of Meeting Minutes*

The chair will ask for approval of the January 21, 2003 MISO/PJM Reliability Plan Review Team meeting minutes.

## Attachments

1. January 21, 2003 MISO/PJM Reliability Plan Review Team meeting minutes
2. MISO/PJM Reliability Plan Review Team Roster

## *Item 1.g Future Meetings*

The Review Team will schedule future meetings as necessary.

# Parliamentary Procedures

**Based on Robert's Rules of Order, Newly Revised, 1990 Edition**

## *Motions*

Unless noted otherwise, all procedures require a "second" to enable discussion.

| When you want to... | Procedure | Debatable | Comments |
|---|---|---|---|
| Raise an issue for discussion | Move | Yes | The main action that begins a debate. |
| Revise a Motion currently under discussion | Amend | Yes | Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and cannot reverse the intent of the main motion. |
| Reconsider a Motion already approved | Reconsider | Yes | Allowed only by member who voted on the prevailing side of the original motion. |
| End debate | Call for the Question *or* End Debate | No | If the Chair senses that the committee is ready to vote, he may say "if there are no objections, we will now vote on the Motion." Otherwise, this motion is debatable and subject to 2/3 majority approval. |
| Record each member's vote on a Motion | Request a Roll Call Vote | No | Takes precedence over main motion. No debate required, but the members must approve by 2/3 majority. |
| Postpone discussion until later in the meeting | Lay on the Table | Yes | Takes precedence over main motion. Used only to postpone discussion until later in the meeting. |
| Postpone discussion until a future date | Postpone until | Yes | Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion. |
| Remove the motion for any further consideration | Postpone indefinitely | Yes | Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively "kills" the motion. Useful for disposing of a badly chosen motion that cannot be adopted or rejected without undesirable consequences. |
| Request a review of procedure | Point of order | No | Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion. |

### Notes on Motions

**Seconds.** A Motion must have a second to ensure that at least two members wish to discuss the issue. The "seconder" is not recorded in the minutes. Neither are motions that do not receive a second.

**Announcement by the Chair.** The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee "owns" the motion, and must deal with it according to parliamentary procedure.

**Revisions.** Technically, revisions to the main motion are accomplished by the Amend procedure. However, immediately after making the motion, and before it is announced by the Chair, another member may ask that the motion be revised. If the original "motion-maker" agrees to the revision, then the revised motion will be the one debated. The original "seconder" need not be consulted, because the original "motion-maker" plus the "reviser" constitute a motion and a second.

## *Voting*

| Voting Method | When Used | How Recorded in Minutes |
|---|---|---|
| Unanimous Consent | When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken. | The minutes show "by unanimous consent." |
| Vote by Voice | The standard practice. | The minutes show Approved or Not Approved (or Failed). |
| Vote by Show of Hands (tally) | To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member). | The minutes show both vote totals, and then Approved or Not Approved (of Failed). |
| Vote by Roll Call | To record each member's vote. Each member is called upon by the Secretary,, and the member indicates either "Yes," "No," or "Present" if abstaining. | The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a "Yes," "No," or "Present" is not shown are considered absent for the vote. |

**Notes on Voting**
**(Recommendations from DMB, not necessarily Mr. Robert)**

**Abstentions.** When a member abstains, he is not voting on the Motion, and his abstention is not counted in determining the results of the vote. The Chair should not ask for a tally of those who abstained.

**Determining the results.** The results of the vote (other than Unanimous Consent) are determined by dividing the votes in favor by the total votes cast. Abstentions are not counted in the vote and shall not be assumed to be on either side.

**"Unanimous Approval."** Can only be determined by a Roll Call vote because the other methods do not determine whether every member attending the meeting was actually present when the vote was taken, or whether there were abstentions.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

# NERC ANTITRUST COMPLIANCE GUIDELINES

## I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or which might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

## II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees
June 14, 2002

## III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Organization Standards Process Manual
- TransitionalProcess for Revising Existing NERC Operating Policies and Planning Standards
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

# MISO/PJM Reliability Plan Review Team Meeting

January 21, 2003
Denver, Colorado

## Minutes

The MISO/PJM Reliability Plan Review Team (Review Team) met on January 21, 2003 in Denver, Colorado. The meeting notice, agenda, and attendance list are affixed as **Exhibits A, B** and **C**, respectively. Individual statements and minority opinions are affixed as **Exhibits D** and **E**. (There were no comments.)

### Administrative Items

Chairman Fidrych opened the meeting, and Larry Kezele announced that a quorum was present. Chairman Fidrych introduced Mr. Jim Goodrich, a member of the NERC Board of Trustees. Chairman Fidrych reviewed the agenda, and encouraged active participation by all present. Chairman Fidrych also called the Review Team's attention to the NERC antitrust policy in the agenda package.

### Minutes

The minutes of the December 4, 2002 Review Team meeting were approved.

### MISO/PJM Reliability Plan Review

Larry Kezele noted that a revised document titled *MISO-PJM Reliability Plan Review*, draft 8 was included in the agenda package. Draft 8 includes the addition of critical dates and events leading to implementation of Day 2 expansion of the PJM LMP market to AEP and DPL. Mr. Kezele noted that the Operating Committee is scheduled to meet on February 4, 2003 to consider the PJM market expansion. Tom Kraynak stated that the ECAR Executive Board has a meeting scheduled for February 6, 2003, at which time ECAR will consider issues related to the PJM market expansion.

### Control Area-to-Reliability Coordinator Mapping

Larry Kezele reviewed the Control Area-to-Reliability Coordinator mapping document included in the agenda, focusing on the changes expected to occur on February 1, 2003. The Distribution Factor Working Group is preparing a change to the Book of Flowgates to reflect the anticipated changes in Control Area-to-Reliability Coordinator mapping. It was noted that some Control Areas have not yet indicated their choice in Reliability Coordinator. Tom Bowe stated that PJM establishes a contractual relationship with each operating entity for which it provides Reliability Coordination services.

Following the discussion related to the proposed changes in the PJM Reliability Plan footprint, Mark Fidrych moved to approve the expansion of the PJM Reliability Plan footprint to include Control Areas

OVEC, DEWO, AEBN, and DLCO effective February 1, 2003, contingent upon receipt of the ECAR Executive Board approval. The motion was approved.

The Review Team stated its desire to inform the Operating Committee, at its February 4, 2003 meeting, that some Control Areas have not indicated their choice in Reliability Coordinator, to replace their existing Reliability Coordinator when that entity ceases to provide services.

George Bartlett stated that the CLEC Control Area would be moving from SPP to Entergy effective March 1, 2003, and that Entergy would present their reliability area change to the Operating Reliability Subcommittee at its February 2003 meeting. Mr. Bartlett noted that the SERC Operating Committee was voting by electronic ballot to approve this change to the Entergy footprint, and Lanny Nickell stated that SPP approved the transition of CLEC from SPP.

The revised Control Area-to-Reliability Coordinator mapping document is attached as **Exhibit F**.

### PJM Control Area Certification

Marty Sidor presented an overview of the recently completed Control Area certification of the PJM Control Area, **Exhibit G**. Mr. Sidor noted that the PJM Control Area bridges both MAAC and ECAR, hence, both Regions participated in the certification process. The Control Area certification was conducted to address two objectives, each resulting from the movement of the former APS Control Area into the PJM Control Area, thereby creating an entity titled "PJM West." Those objectives were:

1. Re-certify the PJM RTO as a MAAC Control Area

2. Investigate PJM operations related to concerns raised by the Interchange Subcommittee

The Control Area Certification Team concluded that the PJM Control Area is compliant with current NERC Policy, and recommended that the MAAC Operating Committee certify PJM as a MAAC Control Area. The MAAC Control Area Certification Report is posted on the Review Team web site at http://www.nerc.com/~filez/miso-pjm.html.

The Review Team discussed each of the issues raised by the Interchange Subcommittee, and concluded that Policies 1 (Generation Control and Performance) and 3 (Interchange) require revision to address DCS event reporting. Tom Bowe stated that APS is considering submission of a Control Area de-certification request.

### Policy Review Task Force Report

Task Force chair Kim Warren stated that at its September 18, 2002 meeting, the Review Team charged the Task Force to identify changes to policy required to support the envisioned implementation plans of MISO and PJM. Mr. Warren presented an overview of the Task Force's findings related to Policies 1, 3 and 9, **Exhibit H**. Mr. Warren stated that Carl Monroe, as chair of the Resources Subcommittee, would be asked to join the Task Force.

The Review Team discussed available options to revise existing policies. Don Benjamin stated that the Task Force should consider the development of waivers to policy required to support the proposed expansion of the PJM market. Such waivers only require Operating Committee approval; however, waivers are not permanent.

In response to a question, Mr. Fidrych stated that the Task Force was not asked to review the Planning Standards and their associated compliance templates. Larry Kezele noted that changes to Policy 9 might result in having to file a revised TLR procedure with FERC.

## MISO/PJM Day 2 Congestion Management

Tom Bowe and Dave Zwergel presented an overview of Version 2a of the *PJM and MISO Proposal – Congestion Management Seams Issue Whitepaper*, dated January 14, 2003. (Secretary's note: The white paper and Mr. Bowe's and Mr. Zwergel's presentation are posted at http://www.nerc.com/~filez/miso-pjm.html.) The presentation focused on the following:

1. Determination of Coordination Flowgates — Mr. Bowe discussed the various studies that PJM would conduct to determine the list of Coordination Flowgates. PJM would present the flowgate list to the Review Team at its February 2003 meeting. The Review Team indicated that the list of Coordinated Flowgates should be the same as that used in the ATC/AFC calculation and coordination processes.

   Mr. Bowe also discussed the creation of flowgates-on-the-fly. He stated that PJM is developing an internal procedure to assure that such flowgates can be created in less than 60 minutes.

2. Market Flow Calculations — Dave Mabry provided an overview of PJM's proposal to determine economic dispatch flows on flowgates external to the PJM market. The PJM proposal includes the determination and inclusion of counter-flows. Load Shift Factors (LSFs) would be calculated every five minutes and used in the market flow calculation process. Pumped storage generating units would be modeled as negative generators when in the pumping mode. Market flows would be calculated for the current-hour and next-hour, and would use data available from the SDX to assure accurate system topology.

   Lanny Nickell noted that the ORS, in June 2001, approved the counter-flow methodology for use in the determination of NNL and tagged transaction impacts. However, this methodology was not implemented. Therefore, Mr. Nickell asked if the Review Team could approve the proposed market flow calculation, wherein only counter-flows associated with PJM internal generators are considered, recognizing the potential comparability and equity issues.

   Ray Kershaw asked how the internal PJM calculation process could be audited. Mr. Kershaw suggested that perhaps information related to the calculations could be uploaded to the IDC, such that the IDC could perform a similar calculation of market flow impacts for after-the-fact audit purposes.

3. Options to Tagging In/Out/Through Interchange Transactions — Dave Zwergel noted that MISO and PJM are considering three options related to the determination of the impact of tagged transactions on flowgates external to the PJM market. Mr. Zwergel noted that the goal of each option is to model the flow impacts of tags as accurately as possible. Mr. Zwergel noted that MISO preferred Tagging Option 3 (calculation of impact from marginal generator to proxy bus) when it implements its LMP market, while PJM prefers implementation of Tagging Option 2 (calculation of impact from marginal generator to load zones or Control Areas).

   Jack Kerr noted that the magnitude of TLR curtailment might change the source of the marginal generation expected to be re-dispatched to reflect the curtailment. Mr. Zwergel acknowledged this potential outcome, and noted that MISO and PJM could perhaps calculate and upload to the IDC several TDF matrices to reflect such an eventuality. Lanny Nickell stated that MISO and PJM would have to calculate tag impacts for all flowgates and not just the Coordination Flowgates discussed above.

4. Options for Determination of Network and Native Load — Tom Bowe stated that two options are being considered for the determination of NNL impact on the Coordinated Flowgates. The

impacts of partial path transmission reservations would not be considered in the day-ahead analysis, unless the reservation has resulted in a schedule.

Doug Hils suggested that implementation of the proposed calculation methodology would effectively result in the assignment of flowgate rights between MISO and PJM, and that the methodology might not be comparable. Tom Bowe suggested that FERC would address comparability and equity issues.

Mr. Bowe also reviewed the section titled "MISO and PJM Outstanding Congestion Management Seams Issues" on pages 31–33 of the congestion management white paper. This section of the white paper presents an overview of efforts made to address each of the issues identified by the Review Team at its December 4, 2002 meeting. The Review Team noted the following:

- ✓ Consolidation of AEP and DPL into the PJM Control Area will result in loss of IDC granularity and the loss of tagging of transactions into or out of those former Control Areas. Some Reliability Coordinators rely on the availability to such tag information for use in their system analysis processes. Mr. Bowe indicated that PJM could provide inter-control zone flows for the current-hour, next-hour and next-day by uploading such information to the IDC, or the SDX, or to a FTP site.

- ✓ IDC versus PJM Calculation of Flowgate Impacts — Mr. Zwergel noted that MISO supports the PJM proposal to independently calculate flowgate impacts, and to upload the results of those calculations to the IDC. Mr. Nickell noted that the IDC Working Group monitors the calculation processes used within the IDC, and suggested that the Working Group could similarly monitor the PJM calculation processes. However, Mr. Nickell also added that if MISO and PJM receive approval to implement their proposed calculations, how could the Review Team or the Operating Committee deny a similar request made by another Control Area. Tony Jankowski noted that other Reliability Coordinators should not be required to change their internal systems to adjust to the changes proposed by MISO and PJM.

- ✓ The Review Team reiterated a desire to see examples of the proposed calculations.

Chairman Fidrych encouraged the Review Team to submit comments on the congestion management white paper to David Zwergel and Tom Bowe.

### Future Meetings

Chairman Fidrych stated that the Operating Committee would meet on February 4 to further consider the reliability issues associated with the expansion of the PJM LMP market. In addition, the Review Team will meet on the morning of February 12, 2003 in Phoenix, Arizona to consider the revised PJM Reliability Plan.

### Adjourn

There being no further business before the Review Team, the meeting was adjourned at 3:08 p.m.

**Larry Kezele**

Larry Kezele
Secretary

# MISO-PJM Reliability Plan Review Team Roster

| Name | Organization | Notes |
|---|---|---|
| 1. Mark Fidrych (Chairman) | Western Area Power Administration | Decision Subgroup |
| 2. Joe Krupar (ORS -MIC) | Florida Municipal Power Agency | |
| 3. Ed Devarona (RCWG) | FP&L | |
| 4. Marty Mennes (ORS-MIC) | FP&L | |
| 5. Bob Priest (ORS) | Yazoo City | |
| 6. Garth Arnott (ORS) | North Carolina Electric Co-op | |
| 7. Greg Stone (ORS-RCWG) | Duke Energy | |
| 8. Jack Bernhardsen (ORS-RCWG) | Pacific Northwest Security Coordinator | |
| 9. Kim Warren (ORS-RCWG) | IMO | |
| 10. Greg Tillitson (RCWG) | CA ISO | |
| 11. Steve Myers (ORS-RCWG | ERCOT | |
| 12. Jim Castle (RCWG) | NY ISO | |
| 13. Julien Gagnon (RCWG) | TransEnergie | |
| 14. Don Gates (RCWG) | ISO NE | |
| 15. Bob Temple (RCWG) | Rocky Mountain-Desert Southwest Reliability Center | |
| 16. James Case (RCWG-CMS) | Entergy | |
| 17. Steve Corbin (RCWG) | Southern Security Coordinator | |
| 18. Cliff Shepard (ORS) | Southern Company Generation and Energy Marketing | |
| 19. Stuart Goza (RCWG) | TVA | |
| 20. Armie Perez (PC-PSS) | CA ISO | |
| 21. Tom Washburn (ATCWG) | Orlando Utilities Commission | |
| 22. Ron Szymczak (ATCWG) | Commonwealth Edison | |
| 23. George Barlett (PC RAS) | Entergy | |
| 24. Tony Jankowski (ORS, MIPS) | WE Energies | |
| 25. Karl Tammar (OC, ESC) | NYISO | |
| 26. Doug Hils (IS) | Cinergy | |
| 27. Tom Bowe (ORS-RCWG) | PJM | MISO-PJM staff or possible members |
| 28. Wayne VanOsdol (RCWG) | MISO | |
| 29. Roger Harszy (ORS-RCWG) | MISO | |
| 30. Dave Zwergel (RCWG) | MISO | |
| 31. Paul Reber (RCWG) | MAIN | |
| 32. Dan Boezio (ORS-RCWG) | AEP | |
| 33. Jack Kerr (RCWG) | Virginia Power | |
| 34. Lanny Nickell (ORS-RCWG) | SPP | |
| 35. Tom Kraynak | ECAR | |
| 36. Richard Bulley | MAIN | |
| 37. Ev Lucenti | Power Decisions | |

February 2003

## Item 2. MISO/PJM Review Team Documentation

The Review Team will review and update, as necessary, the document titled "MISO-PJM Reliability Plan Review." The document was updated and now provides a roadmap leading to the approval of the second phase of implementation of the revised MISO and PJM Reliability Plans. The Review Team may elect to develop milestones leading to the approval of subsequent implementation phases of the revised MISO and PJM Reliability Plans.

### Attachment

MISO-PJM Reliability Plan Review — Dated February 6, 2003

**Revisions in this draft:**

Timetable for Day 2 operation (PJM market expansion into AEP and DPL) currently expected to occur May 1, 2003.

# MISO-PJM Reliability Plan Review

**Draft 9 – February 6, 2003**

## Introduction

The Midwest ISO has expressed reliability and operational concerns regarding the choices of former Alliance companies to participate in the MISO and PJM RTOs. The issues MISO has raised include managing loop flows and seams issues, reliability coordination, and pending generator interconnection requests at its seams. As a result of MISO's concerns, FERC chairman Pat Wood has asked NERC to help resolve these reliability issues. Furthermore, NERC's own policies require Operating Reliability Subcommittee review and Operating Committee approval of all reliability plans that involve significant changes in the membership and operations of RTO organizations.

NERC has an approved process for reviewing reliability plans. However, to address the specific issues that MISO has raised, and to consider MISO's and PJM's intent to bring their organizations into a single market by 2004 in stages, the NERC staff and Technical Steering Committee have developed this special reliability plan approval process.

## Objectives

This document provides the guidelines for conducting a review of the MISO and PJM reliability plans, as well as the plans of ECAR, MAIN, and other Reliability Coordinators affected by the MISO-PJM proposed configuration.

To accomplish this task, NERC needs to:

1. Assemble a team of experts in real-time reliability coordination, system planning (including ATC coordination), and market interface matters to conduct the review

2. Review the joint MISO/SPP and PJM Potential Reliability Issues lists to ensure an understanding of the issues

3. Determine if additional issues need to be addressed

4. Determine MISO-PJM implementation "stages"

5. Assist MISO and PJM in updating their Reliability Plans to address the issues identified in #2 and #3 above. Likewise, assist ECAR and MAIN in updating their Reliability Plans.

6. Work toward MISO's and PJM's agreement that the solutions they jointly develop for managing seams issues are feasible and effective.

7. Provide recommendations for NERC Operating Committee review and action on the revised Reliability Plans of MISO and PJM.

8. Provide recommendations to the Operating Committee for any changes needed to the structure and content of Reliability Plans. Seek comments from MIC and PC.

NERC will also need to set up a project plan (see Timetable) to provide for review of the Reliability Plans and possibly special meetings of the Operating Committee.

## *Information Gathering*

- Review MISO/SPP and PJM Potential Reliability Issues
  - Determine how much detail is needed
  - Contact MISO and PJM for additional information
  - Also contact ECAR and MAIN to see what information they need
- Reliability Plans from adjacent Reliability Coordinators as well as plans from any other Reliability Coordinators affected by the MISO-PJM proposed organization
- List of implementation stages through transition period
  - Implementation timetables (start and end times for each stage)
  - "Trigger point" for each stage
- Additional information (for example):
  - Data accuracy and integrity – what happens if some data is lost? Looks like load or generation has dropped off.
  - Common models and, where necessary, monitoring (of each other's systems)
  - How to coordinate the security-constrained dispatch with TLR procedure
  - How to coordinate with third party systems

## *Analysis*

While concentrating on the MISO and PJM reliability plans, the review team will also need to look at the plans of other Reliability Coordinators affected by the MISO and PJM plans. The analysis needs to include the following issues.

1. Parallel flow management
   a. ATC/AFC coordination
   b. Congestion management
      i. LMP
      ii. TLR
2. Reliability assessments
   a. Timeframes – next hour, next day, etc.
   b. Modeling
   c. Communications
3. Reliability coordination
   a. Uniform terms and definitions
   b. Restoration procedures
   c. Maintenance coordination
   d. Ensure *all* control areas are within the purview of a unique Reliability Coordinator
4. Expansion planning

## *Timetable for Stage 1 Review*

| Date | Event | Comments |
|---|---|---|
| Week of July 22 | Staff activities:<br>1. Contact MISO, PJM, MAIN, and ECAR. Determine official contacts and review this timetable. Adjust as needed.<br>2. Assemble Review Team<br>3. Send background info ("Starter Kit")<br>4. Plan first conference call<br>5. Establish FERC contact | Results of initial discussions with MISO and PJM may result in adjustments to this timetable.<br>Also, need to determine the MISO-PJM implementation stages – what are the "trigger points" that mark the beginning of a new stage. |
| July 31<br>9:00 a.m. EDT | Review Team conference call to:<br>1. Review MISO-PJM issues lists.<br>2. Review issues lists from other Reliability Coordinators<br>3. Decide on additional data required and degree of detail. | At this point, MISO and PJM should know what NERC needs to conduct its review.<br>Decide if modeling experts are needed. |
| August 5 – 16 | MISO, PJM, MAIN, and ECAR prepare Reliability Plans. | |
| August 19 | MISO, PJM, MAIN, and ECAR send Reliability Plans to Review Team | ECAR and MAIN will also review MISO and PJM Reliability Plans |
| Week of August 26 | Review Team reviews Reliability Plans | |
| September 4 | Review Team conference call to discuss issues related to the Reliability Plans | Conf call meeting minutes identify issues to be clarified/addressed in MISO/PJM reliability plans.<br>MAIN and ECAR identified CAs needing to elect RC services. |
| September 9 – 20 | MISO, PJM, MAIN, and ECAR revise Reliability Plans as needed. | |
| September 18 | Review Team to meet in Washington DC to further consider the MISO and PJM Reliability Plans.<br>The ORS will discuss new template for Reliability Plans. | Review Team approved MISO/PJM footprint changes. |
| October 22 | Special OC meeting | MIC, PC and Review Team invited to attend.<br>OC approved MISO/PJM footprint changes. |
| Week of October 28 | Board of Trustees consideration | BoT endorses OC action. |
| November 5 | NERC General Counsel files Initial Report with FERC | |
| **DAY 2 Operation** | | |
| December 4 | Review Team meeting. | MISO and PJM presented preliminary congestion management proposals. |

| | | |
|---|---|---|
| December 18 | MISO/PJM Stakeholders Meeting | MISO and PJM presented congestion management proposals. |
| January 16 | MISO/PJM Stakeholders Meeting | MISO and PJM to present congestion management proposals. |
| January 21 | MISO/PJM Review Team Meeting | MISO and PJM to present congestion management proposals. |
| January 23 | MAIN Operating Committee Meeting | MISO and PJM to present congestion management proposals. |
| January 28 | ECAR Coordination Review Committee and Operation Panel Meeting | MISO and PJM to present congestion management proposals. |
| February 4 | Special OC meeting | MISO and PJM to present congestion management proposals.<br>MIC, PC and Review Team invited to attend. |
| February 6 | ECAR Executive Board Meeting | MISO and PJM to present congestion management proposals. |
| February 12 | MISO/PJM Review Team Meeting | MISO and PJM to present congestion management proposals. |
| March 19 | OC Meeting | PJM seeks endorsement of revised Reliability Plan |
| March 03 | MISO/PJM testing of revised congestion management processes and procedures. | |
| April 03 | MISO/PJM (and other Reliability Coordinator) training of revised congestion management processes and procedures. | |
| May 1, 2003 | PJM Market Expansion – AEP/DPL | |

## Review Team

The Review Team will comprise the following:

1. Operating Reliability Subcommittee
2. Reliability Coordinator Working Group
3. Representative from the Interchange Subcommittee
4. Representative from the Planning Committee
5. Representative from the Planning Committee's ATC Working Group
6. Representative from the Market Interface Committee
7. Representatives from both ECAR and MAIN staffs

### Decision Subgroup

Within the Review Team, NERC will assemble a decision subgroup to provide recommendations for NERC Operating Committee review and action. The decision subgroup comprises members of the Review Team, but excludes MISO/SPP and PJM staff as well as proposed MISO and PJM members.

### Proposed Review Team Roster

| ***Name*** | ***Organization*** | ***Notes*** |
|---|---|---|
| 1. Mark Fidrych (chairman) | Western Area Power Administration | Decision Subgroup |
| 2. Greg Stone (ORS-RCWG) (vice chairman) | Duke Energy | |
| 3. Joe Krupar (ORS -MIC) | Florida Municipal Power Agency | |
| 4. Ed Devarona (RCWG) | FP&L | |
| 5. Marty Mennes (ORS-MIC) | FP&L | |
| 6. Bob Priest (ORS) | Yazoo City | |
| 7. Garth Arnott (ORS) | North Carolina Electric Co-op | |
| 8. Jack Bernhardsen (ORS-RCWG) | Pacific Northwest Security Coordinator | |
| 9. Kim Warren (ORS-RCWG) | IMO | |
| 10. Greg Tillitson (RCWG) | CA ISO | |
| 11. Steve Myers (ORS-RCWG | ERCOT | |
| 12. Jim Castle (RCWG) | NY ISO | |
| 13. Julien Gagnon (RCWG) | TransEnergie | |
| 14. Don Gates (RCWG) | ISO NE | |
| 15. Bob Temple (RCWG) | Rocky Mountain-Desert Southwest Reliability Center | |
| 16. James Case (RCWG-CMS) | Entergy | |
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| 19. Stuart Goza (RCWG) | TVA | |
| 20. Armie Perez (PC-PSS) | CA ISO | |
| 21. Tom Washburn (ATCWG) | Orlando Utilities Commission | |

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| 24. Tony Jankowski (ORS, MIPS) | WE Energies | |
| 25. Karl Tammar (OC, ESC) | NYISO | |
| 26. Doug Hils (IS) | Cinergy | |
| 27. Tom Bowe (ORS-RCWG) | PJM | MISO-PJM staff or possible members |
| 28. Wayne VanOsdol (RCWG) | MISO | |
| 29. Roger Harszy (ORS-RCWG) | MISO | |
| 30. Dave Zwergel (RCWG) | MISO | |
| 31. Paul Reber (RCWG) | MAIN | |
| 32. Dan Boezio (ORS-RCWG) | AEP | |
| 33. Jack Kerr (RCWG) | Virginia Power | |
| 34. Lanny Nickell (ORS-RCWG) | SPP | |
| 35. Tom Kraynak | ECAR | |
| 36. Richard Bulley | MAIN | |
| 37. Ev Lucenti | Power Decisions | |

## Staff Assistance

Larry Kezele – facilitator and NERC staff contact

Dave Hilt

Don Benjamin

## Background

MISO, in presentations to state commissioners in Bismarck, North Dakota on June 24, 2002 and the FERC open meeting on June 26, 2002, presented reliability and operational concerns in relation to the choices of former Alliance companies to participate in PJM ISO and MISO. Issues discussed included, among other things, loop flows, seams issues, and pending generator interconnection requests at seams. Toward the end of the FERC open meeting, Commission chairman Pat Wood asked for NERC's help in resolving the individual reliability issues.

On July 3, the Commission issued a letter to:

Elizabeth A. Moler
Senior Vice President, Government Affairs
Exelon Corp.

Kathryn L. Patton
Senior Vice President and General Counsel
Illinois Power Company

J. Craig Baker
Senior Vice President, Regulation and Public Policy
American Electric Power Service Corp.

David N. Cook
General Counsel
North American Electric Reliability Council (NERC)

Brantley H. Eldridge
Executive Manager
East Central Area Reliability Coordination Agreement (ECAR)

Richard A. Bulley
Executive Director
Mid-America Interconnected Network, Inc. (MAIN)

Nick Winser
Senior Vice President
National Grid

James P. Torgerson
President and CEO
Midwest Independent Transmission System Operator, Inc.

Kenneth Laughlin
Vice President of Market Operations PJM Interconnection, L.L.C.

requesting additional information. The Commission asked specific questions of NERC, MAIN, and ECAR (Attachment A)

On July 5, MISO and PJM jointly provided NERC with a "MISO/SPP and PJM Potential Reliability Issues" list (Attachment B).

On July 15, NERC, ECAR and MAIN filed their joint response with the Commission (Attachment C). The final recommendation in the joint response follows:

> "Based on the foregoing, NERC recommends that, if the Commission approves the proposed MISO-PJM configuration, the Commission condition that approval upon (1) MISO's and PJM's agreement that the solutions they jointly develop for managing seams issues are feasible and effective, and (2) NERC's review and approval of the MISO and PJM Reliability Plans."

On July 17, NERC's president Michehl Gent, Operating Committee chairman Derek Cowbourne, MAIN Executive Director Richard Bulley, and ECAR's manager of operations and resources Tom Kraynak, explained the organizations' response at the Commission's regular meeting.

# Item 3. Discussion of MISO/PJM Day 2 Congestion Management Issues

## Discussion and Action

MISO and PJM will provide an overview of their Day 2 congestion management proposals to mitigate flowgate constraints. MISO and PJM will address each of the issues identified by the Review Team at its December 4, 2002 meeting. Each issue, as captured in the minutes of that meeting, is summarized below. The Review Team will develop resolutions regarding each of the identified issues for consideration by PJM and MISO as they develop revised reliability plans for Review Team and Operating Committee approval.

In addition, the Operating Committee met on February 4, 2003 to consider the MISO/PJM congestion management proposals. The Operating Committee informally agreed that the MISO and PJM RTOs could proceed with their proposal for dealing with the seams issues surrounding their market-based congestion management procedures. The Operating Committee expects to take formal action on the proposal at its March 19–20 meeting, assuming a number of details are resolved. These include available flowgate and available transfer capability coordination, selection of "market coordination" flowgates, treatment of network transmission service under NERC's Transmission Loading Relief Procedure, and tagging.

For additional information about the MISO-PJM-SPP market, visit their special website at http://www.miso-pjm-spp.com/.

MISO and PJM developed a revised *Congestion Management Seams Issue White Paper.* The revised White Paper is posted to the Review Team web page at http://www.nerc.com/~filez/miso-pjm.html

## Attachment

MISO/PJM Congestion Management Seams Issue White Paper, dated January 14, 2003, Version 2a (Clean copy)

## Summary of Issues Identified by the Review Team

### *Item 3.a PJM's Proposed Market Flow Calculation*

Need details on the methodology, process, and assumptions of proposed method to calculate market flows, as well as example calculations. Market flow calculation should reflect the actual physics of the system.

- ✓ The calculation should be conservative when determining the flows resulting from the market dispatch to avoid over-scheduling the transmission system.
- ✓ Market flow limit is not necessarily an Operating Security Limit, or a facility limit.
- ✓ Market flows calculated from the day-ahead dispatch are considered equivalent to service to Network and Native Load (NNL) customers, and would be treated as using Firm Transmission Service – Priority 7 for curtailment purposes. Market flows, calculated *after* the day-ahead dispatch, are considered as using Non-firm Network (from non-designated resources) – Priority 6.

- ✓ PJM tools and processes capable of calculating LMP dispatch impacts on all identified flowgates. Why re-create these tools and processes within the IDC?

- ✓ Recognize potential costs of implementing LMP market technology across the Eastern Interconnection. Create technology once, within the IDC.

- ✓ Industry oversight of calculation process — Several NERC groups oversee the IDC model development and functionality (e.g. the IDC Working Group and the Distribution Factor Working Group). Is industry oversight needed of the PJM flowgate impact calculator?

- ✓ Cost and implementation schedule of IDC upgrades. Details of uploading LMP calculated flowgate impacts to IDC to be determined.

- ✓ Flowgate impacts calculated every five minutes, not just hourly as currently done by IDC.

- ✓ IDC may require more near real-time data from the NERC ISN.

- ✓ IDC Modeling of Control Zones — Concern for loss of IDC granularity, perhaps upload control zone-to-control zone "interchanges" to the IDC. IDC is a transaction-based impact calculator; inter-control zones energy transfers could be tagged like dynamic schedules.

- ✓ Wide-Area Effects of Security Constrained Economic Dispatch

    1. Impact calculation process, when applied to a larger PJM footprint may reduce the impact on external flowgates; however, this potential drawback is offset by the fact that more flowgates are internalized within the LMP market.

    2. Network resources to network loads. Not all loads in PJM are firm network load. Could create a property rights issue.

- ✓ Model Synchronization — Using different models and processes to calculate ATCs or flowgate impacts will lead to different results. Synchronization of input data files will help minimize the discrepancies.

- ✓ Communications of Flowgate Curtailments to Reliability Coordinators — Loss of E-Tag data may make it more difficult for Reliability Coordinators to analyze the system.

- ✓ Calculation of Multiple Curtailment Requests —PJM will re-dispatch to alleviate an internal constraint, such re-dispatch to be constrained by recognizing its impacts on external flowgates.

## Item 3.g Generation-to-Load Distribution Factor (GLDF) Calculation

The GLDF calculation methodology is driven by assumptions related to the location of the load. As the PJM load zone gets bigger, there will be an impact on the GLDF calculation.

## Item 3.h ATC/AFC Calculation and Consideration of External Flowgates

- ✓ Transmission reservation and scheduling process across MISO and PJM should be transparent to transmission customers.

- ✓ PJM will mitigate overloads due to the non-firm portion of its market flow through LMP-based re-dispatch, even on non-PJM flowgates.
- ✓ PJM market flows on external flowgates would be limited to the flowgate capacity remaining following the identification and scheduling of flowgate owner impacts.

### *Item 3.b Transmission Allocation*

Need details on the prioritization of market flows relative to NERC transmission service priorities 0–7, and the steps required to relieve constrained flowgates.

### *Item 3.c Control Area/Control Zone Responsibilities*

Need to clearly define Operating Policy changes, waivers, or certifications required to permit security-constrained economic dispatch over multiple, existing Control Areas that do not require the tagging of flows between control zones. Changes or waivers to Policies 1, 3 and 9 may be required. **(Note: The Review Team appointed a Policy Review Task Force at its September 18, 2002 meeting. The Task Force will present its findings and recommendations later in the agenda.)**

### *Item 3.d Tagging In/Out/Across Markets*

Need details of methodology for tagging transactions moving into, out of, or across the market. Such methodology should reflect the granularity available today in the IDC, i.e., Control Area-to-Control Area granularity.

- ✓ MISO and PJM trying to develop a compromise. Considering using the former Control Area within PJM footprint closest to the sourcing or sinking Control Area external to the footprint, as the sink or source

### *Item 3.e Selection/Creation of Market/TLR Coordination Flowgates*

Need to ensure that the criteria for selecting flowgates includes all flowgates significantly impacted by market flows. Present process uses a 5% threshold, which may not be adequate for anticipated future operations.

- ✓ Consider eliminating the 5% threshold, and calculate market impact on basis of MW impact.
- ✓ Historical TLRs may not be reflective of future transmission usage, especially transmission congestion. Provide market flow impact on all identified flowgates.
- ✓ Creation of Market Coordination Flowgates in Real-time — A procedure to address the creation of "on-the-fly" flowgates to be developed.

### *Item 3.f IDC versus LMP Calculation of Flowgate Impacts*

The Congestion Management White Paper presents information related to an IDC change order to upload PJM-calculated flowgate impacts to the IDC. The IDC Granularity Task Force is also developing a business case to increase IDC granularity. Approval and implementation of the IDCGTF business case will allow the IDC to calculate flowgate impacts as is currently being done today. **The Review Team will decide which business case to pursue.** Related sub-issues include:

- ✓ Comparability issue?

- ✓ Timing of information exchange to support ATC/AFC calculation processes is critical. Validation modeling data is required.
- ✓ SDX files may require more frequent updating.
- ✓ Need to address flowgates with negative AFCs.
- ✓ ATC/AFC coordination across the Eastern Interconnection

## *Item 3.i Timing of Hold Harmless Settlement Discussions*

FERC directed several entities to propose a solution to the contract tie capacity reliability issue, which will effectively hold harmless utilities in Wisconsin and Michigan from any loop flows or congestion that results from the proposed configurations and dispatch of MISO and PJM.

## *Item 3.j Contingency Plans to Proposed Implementation*

### Summary of Issues Identified by the Operating Committee (February 4, 2003)

1. How to ratchet down over-subscribed flowgates. (Some flowgates that are used for the granting of transmission service are currently over-subscribed in the ATC/AFC processes. The concern rests with congestion management for these flowgates following transition to the PJM LMP market.)

2. Deliverability studies to evaluate flows from new network resources that aren't covered in historic data. (MISO and PJM asked to demonstrate, by example, potential flow changes resulting from the transition to the PJM LMP market.)

3. Resolution of ATC versus AFC coordination. (MISO and PJM are developing ATC/AFC calculation and coordination processes. How will those ATC/AFC processes be coordinated with external ATC/AFC processes?)

   - ✓ Gap between ATC/AFC coordination time and allocation of use of NN-6 priority.
   - ✓ Market clearing time versus other deadlines for selling firm transmission

4. Need examples to show NNL calculations and a description of the process and procedure to be used to calculate and upload to the IDC the results of the NNL calculations.

5. Clarify if TLR Procedure needs changing to accommodate NN-6 pro-rata curtailment. (MISO and PJM need to determine if this is a transmission tariff issue or a Policy 9 (TLR policies and procedures issue).

6. Any problems with different calculation periods: PJM every five minutes versus IDC timing. (This issue should be addressed by the IDC Working Group during its consideration of implementation of Change Order 114.)

7. Describe TLR Procedure, as it will be implemented by MISO and PJM following the transition to the PJM LMP market. (Include marginal unit identification and associated impact and redispatch.)

8. MISO and PJM resolution of outstanding details as identified in presentation to the Operating Committee.

9. Training requirements of Reliability Coordinators and other operating entity personnel to successfully transition AEP and DPL to the PJM LMP market. Involves NERC staff, possibly OATI.

10. Identify data needed from third parties for coordinated flowgates.

    ✓ Including data formats, protocols

# DRAFT

# PJM and MISO PROPOSAL Congestion Management Seams Issue WHITEPAPER Version 2a

January 14th VERSION

# OUTLINE

# 1. EXECUTIVE SUMMARY

a. Attached is the second draft of the PJM MISO Congestion Management Proposal Whitepaper. This second draft differs significantly from the first draft, because it provides far more detail in the areas of Market Flow Calculation, NNL determination, the Tagging of In/Out/Through transactions, and flowgate determination. These additional details are the result of multiple meetings between the RTO's as well as meetings with the NERC community and the industry's associated stakeholders. Some of these review meetings included:

1) Joint NERC CMS, IDCWG, and the MISO/PJM Review Team (NERC ORS and RCWG) Meeting
2) NERC Interchange Sub-committee Meeting
3) MISO/PJM Open Stakeholders Meeting – December 16th

b. As PJM and MISO expand and implement their respective markets one of the primary seams issues that must be resolved is how congestion management will be implemented in areas that currently do not have similar markets. There are additional equally important MISO and PJM seams issues before FERC, NERC and the Stakeholders. These additional seams issues include ATC/AFC coordination, Contract Tie Capacity, Different Definitions and Procedures, Facilities in Close Electrical Proximity Under Different RTOs, Michigan and Wisconsin Hold Harmless, Single Rate, Tariff, and operational and financial impact on market participants of adding new member(s). These additional seams issues are being addressed in other forums and will be resolved before the PJM market expands.

c. MISO is actively working with PJM and Stakeholders on the development of the Congestion Management (TLR/Market and Market/Market) proposed solutions. MISO and PJM have made significant progress in exploring and developing alternatives for resolving the issues. However, Stakeholders have expressed concern with some of the proposed solutions. Accordingly, MISO is looking forward to additional feedback from the January 16, 2003 Reliability Seams Workshop, written comments on this revised white paper, and any alternative proposals by Stakeholders before considering making recommendations on the solution alternatives. There are still outstanding issues related to allocation of transmission usage and prioritization of flows, tagging of flows in, out, or across market, and the criteria for determining Market/TLR coordination flowgates. MISO will continue to work with PJM and Stakeholders on the development of proposed solutions to the congestion management seams issues. These outstanding issues are detailed in the Resolved & Outstanding Issues section of this paper.

d. This Whitepaper provides PJM/MISO's conceptual design of the means to resolve this seams issue. The intent of sharing this conceptual design is to facilitate further discussion as well as identify issues as PJM and MISO, finalize their proposed future procedures and systems. The concepts are intended to provide a framework for other RTO's as they implement markets over large regions.

e. This proposed solution will greatly enhance current IDC granularity by leveraging currently developed real-time applications to monitor and react to system flows on flowgates within the regions that do not have markets. In brief the proposal includes the following concepts:

1) Market RTOs will agree to observe limits on an extensive list of coordinated flowgates.

2) Like all control areas, Market RTOs will have Network and Native Load (NNL) impacts upon the coordinated flowgates.

3) Market RTOs will determine these NNL values using various forms of analysis and constrain its day ahead market to honor the NNL contributions upon the selected flowgates.

4) In real-time, Market RTOS will calculate and monitor when the actual and projected flows exceed these NNL limits.

5) Market RTOs will post the NNL MW flow and additional non-firm economic market flow and the actual and projected market flow to the IDC.

6) When there is a TLR3a or higher called on one of these selected coordinated flowgates, and the Market RTO's actual/projected market flows exceed the NNL limits, Market RTOs will redispatch in order to provide the required MW relief, per the IDC congestion management report.

7) When there is a TLR 5a or 5b, all TPs will curtail or redispatch their respective systems to provide their shares of NNL reductions.

8) Because the IDC will have the real-time/projected flows throughout the Market RTO's system (as represented by the impacts upon various coordinated flowgates) the IDC will have enhanced granularity.

Please direct all questions and comments to Tom Bowe (610-666-4776; bowet@pjm.com) or David Zwergel (317-249-5452 and Dzwergel@Midwestiso.org )

## 2. PURPOSE

The purpose of this Whitepaper is to provide the philosophy and conceptual design behind PJM/MISO's proposal to resolve the Congestion Management Seams Issue. It is PJM and MISO's intent that comments subsequent to the publishing of this Whitepaper, will allow us to work with NERC in coordinating the required project work. By working together to quickly resolve this seams issue, the NERC Community is addressing an issue that is fundamental to the industry moving toward the Standard Market Design (SMD).

## 3. PROBLEM STATEMENT

**a. PROBLEM SUMMARY** – As PJM/RTO's expand their market footprints, the markets may internalize all generation under a single dispatch and the resulting energy flows are no longer tagged. All generators in a single market/single dispatch can equally serve all loads on network service. Because these flows are no longer tagged the NERC Interchange Distribution Calculator (IDC) no longer has the ability to capture these flows in its calculations. This impact of larger markets is typically referred to as "a loss of IDC granularity." As a result the IDC's diminished granularity it is argued that the IDC output is not as accurate (the schedules selected for curtailment may not be as effective in providing relief) and the RTO flows are no longer available for curtailment (an issue of comparability). As a result of these issues the fundamental questions include:

1) How are parallel flows effectively managed
2) How do non-market operational areas control system flows once the IDC loses current granularity?
3) Are there other ways to maintain and/or enhance IDC granularity?
4) What are the curtailment priorities?

b. PJM and MISO have further defined this problem/seams issue in its FERC filings and with the NERC MISO/PJM Review Team in the following manner:

1) *BACKGROUND - Parallel flow issues that require close coordination among neighboring utilities exist today throughout the Eastern Interconnection. Parallel flows are a result of the interdependency of the generation dispatch and the transmission system usage between neighboring systems. Parallel flows will continue to exist under larger RTO operations that will likewise require close coordination to maintain reliable operations. Specific issues related to parallel flows issues include: Congestion Management Procedures and ATC/AFC Coordination.*

2) *STATEMENT OF ISSUE –* ***Congestion Management*** *- MISO will continue to use a TLR-based congestion management process prior to implementation of the MISO market, and an LMP congestion management*

*process after MISO implements its market. PJM, under its market operations, will use their LMP-based congestion management process and TLR. Because there are two different congestion management methods until a joint and common market is implemented, the RTO's will need to closely coordinate operations to ensure reliability.*

3) *COMPLEXITIES*
   a. *In an LMP based market there are no internal transactions to tag. A security constrained economic dispatch is used to dispatch generation for the entire region. Generation transfers are used to adjust the tie line schedules based on the results of the security constrained economic dispatch for multiple control zones.*
   b. *The security constrained economic dispatch currently does not automatically honor external system constraints. Identifying and mitigating congestion impacts due to external system influences requires a different approach than contract path and use of TLR.*
   c. *An effective coordination agreement between MISO and PJM is necessary to minimize the probability of Level 5 TLR's.*
   d. *Market-to-market interfaces must also be addressed once MISO implements its market. Market-to-non-market interfaces will continue to be addressed with other areas of the Eastern Interconnection.*

**4. GOALS of the PROPOSAL:** PJM and MISO have committed to developing a solution to the congestion management seams issue by focusing the solution on achieving the following goals:

a. Develop a congestion relief process whereby transmission overloads can be eliminated through a shared/effective reduction in flowgate or constraint usage by MISO, PJM, and other Reliability Coordinators.
b. Develop a procedure for managing congestion when flowgates are impacted by tagged and non-tagged energy flow.
c. Agree on a predefined set of flowgates or constraints to be considered by both organizations, and a process to add to this set as necessary.
d. Allocate usage of flowgates or constraints - Develop agreement by which each RTO will consider its own flowgate or constraint usage as well as the usage of the other RTO when it determines the amount of flowgate or constraint capacity remaining.
e. Develop a procedure for determining priorities of energy flows.
f. Agree on steps to be taken by the two RTOs to unload a constraint on a shared basis.
g. Confirm that the solution will be equitable solution for all parties.
h. Determine whether procedure(s) for managing congestion will differ based on where flowgate is located (I.e., Inside PJM, Inside MISO, Outside PJM and MISO).
i. Determine the best way to calculate net flow due to one LMP market's impact on flowgates outside of that market

## 5. ASSUMPTIONS

a. Point to Point schedules sinking in, sourcing or passing through PJM/RTO will still be tagged.
b. The IDC is needed for at least the interim between the interconnection's current state and SMD application
c. The LMP market can compute the impacts of the market dispatch on the flowgates at every LMP cycle (5 minutes).
d. Market RTO's EMS has the capability to monitor and respond to real-time and projected flows created by its real-time dispatch
e. The Reliability Coordinator where the flowgate resides will be responsible for monitoring the flowgate, determining the amount of relief needed, and entering the required relief in the IDC.
f. The IDC can be modified to accept the calculated values of the impact of real-time generation in order to determine which schedules require curtailment in conjunction with the required Market RTO's redispatch
g. The IDC will calculate the total amount of MW relief required by the Market RTO (schedule curtailments required plus the relief provided by redispatch).
h. The developed process will be totally auditable and independent.

## PROPOSAL

**a. SUMMARY:** The MISO/PJM proposal has three significant elements these elements include:

1) **Process to determine the external Flowgates that RTO's with markets will monitor**

2) **Definition of what flows will be assessed and what RTO actions do these flows trigger**

3) **Process to provide the detailed analysis of these flows to the NERC IDC in order to maintain/enhance IDC granularity.**

**b. Process/Criteria to Determine Externally Monitored Flowgates:** Market RTO will conduct sensitivity studies to determine which external flowgates (outside the Market RTO) The Market RTO's control zone's (currently the Control Areas that exist today in the IDC) NNL flows have a significant affect upon. The Market RTO will perform the following 3 studies to determine which flowgates the Market RTO will monitor and help control:

**Study 1) – IDC Base Case** (no transmission outages – using the IDC tool)
The IDC can provide a list of flowgates for any user-specified Control Area whose GLDF (Generator to Load Distribution Factor (NNL)) impact is 5% or greater. The Market RTO will use the IDC capabilities to develop a preliminary set of flowgates. This list will contain external flowgates that are impacted by 5% or greater by the current Control Areas that will be joining the Market RTO as Market control zones/areas. Using the *present* control area representation in the IDC (e.g. pre-RTO expansion), if any one generator has a GLDF (Generator to Load Distribution Factor) greater than 5% as determined by the IDC, this flowgate will become a candidate for monitoring by the Market RTO.

**As an example**, consider the PTDF flowgate #3301:

**Flowgate #3301 - Tazewell-Mason 138 kV line**

This flowgate is located in the Central Illinois Light Company control area, which is joining the MISO RTO. GLDF obtained from the IDC indicate that there are two units in the Com-Ed control area (Com-Ed is joining the PJM RTO) which have a GLDF greater than 5%.

Although there are about 150 generators in the Com-Ed area that do not have a GLDF greater than 5% (and some units which have a negative GLDF), the fact that there is at least one generator with a GLDF greater than 5% qualifies this flowgate for inclusion in the PJM RTO list of flowgates that this proposal will respect.

**Study 2) – IDC PSSE Base Case** (no transmission outages–offline study)
In order to confirm the IDC analysis and to provide a better confidence interval that the Market RTO has effectively captured the subset of flowgates that it has a significant impact upon, a MUST power-flow study will be conducted. The Market RTO will perform off-line studies (using the IDC PSSE base case) to confirm the IDC analysis and will study lowering the % impact threshold to capture any significantly impacted flowgates that fall below the 5% limit.

**Study 3) – IDC PSSE Base Case** (transmission outage offline study)
In order to determine outage conditions, if any, that may cause the Market RTO future control zones/areas to have a significant impact on external flowgates, The Market RTO will perform 2nd contingency (n-2) analysis (internal and external outages). This study will be performed offline using MUST powerflow capabilities. Similar to Study 2, the Market RTO will lower % impact threshold to capture any significantly impacted flowgates that fall below the 5% limit.

**Study 4) – Control Area to Control Area –**
For those situations where CAs are being added into a market, there will be a flowgate analysis performed to determine which flowgates are impacted by greater than 5% for transactions between each of the CAs joining the market and between each of the CAs joining the market and the market they are joining. This study will use Transfer Distribution Factors (TDFs) from the IDC. Flowgates that are impacted by greater than 5% as determined by the IDC will become a candidate for monitoring by the Market RTO.

**Additional ways to help determine this list of flowgates include:**

a. PJM and MISO will work with NERC and the TLR history to further validate this list of proposed flowgates.
b. Request all Control Areas in the Eastern Interconnection to provide PJM a list of flowgates (including outage conditions) they believe will be affected by the future PJM control zones NNL flows. This list would be evaluated by PJM and MISO through power-flow studies.
c. PJM will also implement the rulings of the Michigan/Wisconsin Hold Harmless proceedings.
d. This list will be reviewed by various Regional and NERC Committees (ORS/OC) to ensure its appropriateness.
e. Use of a 5% threshold in the studies may not capture all flowgates that experience a significant impact due to market operations. The RTOS have agreed to adopt a lower threshold at the time NERC implements the use of a lower threshold in the TLR process.

### c. Draft List of Flowgates

The following two lists are intended to contrast initial study results and historical information regarding TLR activity. The first list the ECAR staff provided and the second list the MISO staff provided. Those flowgates that PJM's initial analysis have shown the need for inclusion into this proposal are highlighted in **BOLD**.

#### 1. Comparison to List of ECAR's Most Congested Flowgates

*History of TLRs Last 12 Months*

| | | |
|---|---|---|
| KANAWA RIVER – MATT FUNK 39 TLRs | AEP | |
| WYLIE RIDGE 500-345 kV #7 XFMR | 36 TLRs | PJM |
| CLOVERDALE - LEXINGTON 500 kV | 26 TLRs | AEP & VP |
| GHENT 345-138 kV XFMR | 25 TLRs | |
| BLACK OAK - BEDINGTON 500 kV | 24 TLRs | PJM |
| CLIFTY CREEK - NORTHSIDE 138 kV | 18 TLRs | |
| SOUTH CANTON 765-345 kV T3 XFMR | 15 TLRs | |
| BLUE LICK 345-161 kV XFMR | 14 TLRs | LGEE |
| COOK - PALISADES 345 kV | 5 TLRs | |
| BEDINGTON - DOUBS 500 kV | 4 TLRs | |
| GHENT - BATESVILLE 345 kV | 4 TLRs | |
| TWIN BRANCK - ARGENTA 345 kV | 4 TLRs | |
| NEWTONVILLE - CLOVERPORT 138 kV | 4 TLRs | |
| BROWN – SOUTH FAWKES | 3 TLRs | |
| BLUE LICK – BULLIT 161 kV | 3 TLRs | |
| JACKSONS FERRY - ANTIOCH 500 kV | 2 TLRs | |
| KYGER CREEK - SPORN 345 kV | 2 TLRs | |
| CLIFTY CREEK - CARROLLTON 138 kV | 2 TLRs | |
| BENTON HARBOR - PALISADES 345 kV | 1 TLR | |
| MT. STORM - MEADOWBROOK 500 kV | 1 TLR | |
| WEST LEXINGTON - BROWN 345kV | 1 TLR | |
| KAMMER 765-500 kV XFMR | 1 TLR | |
| TWINBRANCH 345-138 kV XFMR | 1 TLR | |
| BROWN – WEST LEXINGTON 345 kV | 1 TLR | |
| FT. MARTIN - PUNTYTOWN 500 kV | 1 TLR | |
| COOK - OLIVE 345 kV | 1 TLR | |
| ARGENTA - PALISADES | 1 TLR | |

## 2. Comparison to List of MISO's Most Congested Flowgates

| Top MISO TLR Flowgates 12/15/2001 - 9/30/2002 | | | | |
|---|---|---|---|---|
| | Number of TLR Events | | | |
| FG Name | TLR 3 | TLR 4 | TLR 5 | Total |
| N.Appleton-LostDauphin 138 for Kewaunee 345-138 TR | 28 | 37 | 0 | 65 |
| KEWAUNEE XFMR+KEWAUNEE-N APPLETON | 27 | 16 | 0 | 43 |
| Stiles-Pioneer 138 for N.Appl-WhiteClay138 | 14 | 23 | 0 | 37 |
| EAU CLAIRE-ARPIN 345 KV | 27 | 0 | 4 | 31 |
| LOR5-TRK RIV5 161KV/WEMPL-PADDOCK 345KV | 27 | 0 | 1 | 28 |
| MWSI | 26 | 0 | 0 | 26 |
| Ghent 345/138 Xfmr for loss of Ghent-W. Lexington 345 | 16 | 7 | 0 | 23 |
| PADDOCK XFMR 1 + PADDOCK-ROCKDALE | 21 | 0 | 0 | 21 |
| Stiles-Amberg 138 & Stiles-Crivitz 138 flo Morgan-Plains 345 | 0 | 18 | 0 | 18 |
| Blue Lick 345/161 XFMR-Baker-Broadford | 15 | 2 | 0 | 17 |
| Northside-Clifty Creek 138 (flo) Trimble Co.-Clifty Creek 345 | 7 | 10 | 0 | 17 |
| Albers-Paris138 for Wemp-Padock 345 | 16 | 0 | 0 | 16 |
| N.PLATTE-STVL /GENTL-REDWIL | 11 | 0 | 2 | 13 |
| Brown South-Fawkes 138 kV | 12 | 0 | 0 | 12 |
| Blackhwk-Cor X54 for Paddock-ROR X39 138 | 11 | 1 | 0 | 12 |
| ROCKDALE XFMR 2 + PADDOCK XFMR | 8 | 2 | 1 | 11 |
| Stiles-Amberg 138 for Morgan-Plains 345 | 2 | 9 | 0 | 11 |
| Poweshiek-Reasnor 161 for Montezuma-Bondurant 345 | 11 | 0 | 0 | 11 |

## d. Process to Develop Flowgates on the Fly

1) For temporary Flowgates developed 'on the fly', the same sensitivity analyses as described under section 6B (Process/Criteria to Determine Flowgates) will be performed by the RTO. The intent of this process is to complete all of this analysis and changes in 60 minutes or less –or as close to real-time as possible.

2) If the temporary flowgate meets the criteria as specified, the RTO will incorporate the new flowgate into the monitoring process and the RTO will calculate both a market flow and NNL value as soon as possible. The RTO will provide these values to the IDC in the same manner as market flows and NNL values are provided to the IDC for permanent flowgates. Off-line load flows required to perform the analysis and determine any values needed will saved on a daily basis to expedite the required calculation.

3) As is presently the case for any temporary flowgate, the IDC will identify contracts sourcing out of or sinking into the RTO that exceed the IDC threshold level and are therefore subject to curtailment.

4) It is expected that discussions between the Reliability Coordinator creating the temporary flowgate and the LMP Market operator will occur to ensure that any contributing circumstances requiring the temporary flowgate are understood and known.

5) If in the event of a system emergency (TLR 5 or higher) and the situation requires a response faster than the process may provide, the RTO's will coordinate respective actions to provide immediate relief until final review.

### e. Defining Monitored Flows

1. The transfer of energy from generating resources to customer load results in flows across the transmission system. This associated energy flow is either scheduled or unscheduled as well as Firm or Non-Firm.

2. 'Unscheduled' flow (a.k.a. 'loop flow') is the result of physics. Energy will flow across the paths of least resistance which may of may not be path that the energy was scheduled, or 'contracted' to flow on. When energy is transferred between two willing parties some of that energy may flow on the transmission facilities of a third party. It is this flow across the third parties facilities that are referred to as loop flow or unscheduled flow.

3. Additionally, unscheduled flow can occur as the result of serving native customer load. As part of an interconnected system, each control area will impact other control areas' transmission facilities as the control area serves its own native load with its available capacity. Problems arise when these parallel flows far exceed the flows typically generated by network resources serving network load.

4. The combination of scheduled flow, unscheduled flow and native load (both internal and external to a control area) can result in actual flows exceeding the limit of a transmission facility. Controlling this flow is typically achieved through generation shifts via NERC TLR implementation or redispatch.

5. A primary concern related to larger markets/control areas is that as additional control areas are incorporated and the footprint of the new area expands, the internalized generation of this larger area now has the ability to serve all loads using network service. These flows then become intra-area transfers, which are no longer tagged in the NERC IDC. Consequently, the IDC does not have the ability to capture and control these intra-area flows; thereby, impacting the TLR process. The remedy to this concern involves separating the flows that are above and beyond the serving of native load – these flows being the result of the "economic dispatch".

6. "Market Flows" are defined by MISO/PJM as the flows generated from both the Economic Dispatch and the Network to Native Load (NNL) flows created by a control areas dispatch. As such there are firm and non-firm components to the Market Flows. The firm components consist of both the flows generated by NNL and those schedules flowing on Bucket 7F transmission reservations. Network and native load is all load that is served by the output of any network resources. The NNL Flows are in essence the parallel flows created by the firm use of one CA serving its load upon another CA's particular. <u>For the purposes of this proposal, both the firm transmission (Bucket 7F) and the NNL will be referred to as "NNL".</u>

The following chart attempts to compare the priority of flows whether they be the result of transaction based impacts or LMP impacts.

| | Transaction Based Impacts | LMP Based Impacts |
|---|---|---|
| **MARKET FLOWS** | Tagged Non-Firm Network 6-NN→ | → Economic Dispatch |
| | Network and Native Load → | → Network and Native Load |
| | Tagged Firm 7F → | |

7) The key to the problem is determining the impact of the RTO's "Economic Dispatch" on the various third party flowgates. When the values of these economic dispatch flows are known the flows can be treated as equivalent to non-firm network (Bucket 6NN). As such, the RTO/Interconnection can control these economic dispatch flows under the same TLR 3 actions used to reduce 6NN flows.

8) The <u>proposed method of determining these Economic Dispatch Flows is to back out the firm NNL flows, leaving the remainder as the ED flows</u>. The reverse engineering to determine these flows could be represented by the following equation:

ECONOMIC DISPATCH Impact on a Flowgate = RTO's Total Market Flows On Flowgate - RTO's NNL Impacts On the Flowgate

9) If the impact of the economic dispatch on the flowgate is greater than the Network Native Load impact, this difference will be available for curtailment under a TLR 3. Effectively, the impact of the PJM RTO economic dispatch over and above the impact of PJM RTO's Network Native Load is 'tagged' in the IDC with a priority of Non-Firm Network (6-NN).

10) The next two sections define how the RTO will calculate the Total Market Flows and determine the NNL value.

## f. Determining Real-Time Market Flows

1) The determination of "Market Flows" builds on the "Per Generator" methodologies that were developed by the NERC Parallel Flow Task Force. The "Per Generator Method Without Counter Flow" was presented to the NERC Security Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC) and both committees have approved this methodology. This methodology is presently used in the IDC to determine NNL contributions (refer to Appendix D, Parallel Flow Curtailment Procedure Reference Document).

2) By expanding on the Per Generator Method, the 'Market Flow" calculation evolves into a methodology very similar the "Per Generator Method With Counter Flow" while providing a granularity on the order of the most granular method developed by the IDC Granularity Task Force.

3) Similar to the Per Generator Method, the calculation method is based on Generator Shift Factors (GSFs) of an LMP area's assigned generation and the Load Shift Factors (LSFs) of its load on a specific flowgate, relative to a system swing. The GSFs are calculated from a single bus location in the base case (e.g. the terminal bus of each generator) while the LSFs are defined as a general scaling of the LMP area's load. The Generator to Load Distribution Factor (GLDF) is calculated as the GSF minus the LSF.

4) The determination of the "Market Flow" contribution of a unit to a specific flowgate is the product of the generators GLDF multiplied by the actual MW output of that generator.

5) The total "Market Flow" of a specific flowgate is the sum of the "Market Flow" flow contribution of each generator in the LMP area.

6) The evolution of the Per Generator Method into the "Market Flow" calculation occurs from the following enhancements:

    a. The contribution from *all* LMP area generators will be taken into account.
    b. In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. These calculations will use counter-flows down to 0% with no threshold. NERC may need to modify the IDC to model counter-flows to ensure comparability.

    c. The contribution of all LMP area generators is based on the present output level of each individual unit.

d. The contribution of the LMP area RTO load is based on the present demand at each individual bus.

7) By using the real-time values of generation and load, the "Market Flow" calculation is effectively implementing the most granular method of the six IDC Granularity Options considered by the NERC IDC Granularity Task Force (i.e. Option #1 – Every Generator to Every Load Bus).

8) Further considerations:

9) Units assigned to serve an LMP area's load do not need to reside within the LMP area's footprint to be considered in the "Market Flow" calculation. However, units outside of the LMP area will not be assigned when it is expected that those units will have tags associated with their transfers.

10) Additionally, there may be situations where the participation of a generator in the LMP market would be less than 100% (e.g. a unit jointly owned in which not all of the owners are participating in the LMP market).

11) Finally, imports into or exports out of the LMP area must be properly accounted in the determination of "Market Flows":

a. when the actual generation of the LMP area exceeds the total load of the LMP area, the LMP area is exporting energy. These exports are tagged transactions that must be accounted for in the "Market Flow" calculation. This will be done by scaling down the actual output level of each LMP area generator by the load to generation ratio.

b. when the actual generation of the LMP area is less than the total load of the LMP area, the LMP area is importing energy. These imports are tagged transactions that are not to be included in the determination of "Market Flows". As such, the LMP area's generation is not scaled (scaling = 1.00).

c. This scaling factor may be adjusted based upon the selection of which of the proposed tagging options is implemented.

**12) Summary of calculations:**

For a specified flowgate, the "Market Flow" impact of an LMP area is given as:

**Total "Market Flow" = Σ ("Market Flow" contribution of each unit in the LMP area)**

where,

**"Market Flow" contribution of each unit in the LMP area = (GLDF) (Real-Time generator output) (Participation Percent/100) (Scaling Factor)**

and,

**GLDF** is the Generator to Load Distribution Factor

**Real-Time generator output** is the present MW level of the generator

**Participation Percent** is the share of the unit participating in the LMP area's market

**Scaling Factor** is the total LMP area load to total LMP area generation ratio (Scaling Factor equals 1.00 if the LMP area is importing).

13) The real-time and projected "Market Flows" will be calculated on-line utilizing the LMP area's state estimator model and solution. This is the same solution presently used to determine real-time LMPs as well as providing on-line reliability assessment and the periodicity of the Market Flow calculation will be on the same order.

14) Inputs to the state estimator solution include the topology of the transmission system and actual analog values (i.e. line flows, transformer flows). This information is provided to the state estimator automatically via SCADA systems such as NERC's ISN link.

15) Using an on-line state estimator model to calculate "Market Flows" provides a more accurate assessment than using an off-line representation for a number of reasons:

a. The calculation incorporates:

1. Actual real-time and projected generator output. Off-line models often assume an output level based on a nominal value such as unit maximum capability but there is no guarantee that the unit will be operating at that assumed level or even on-line. Off-line models may not reflect the impact of pumped-storage units when in the pumping mode, these units may be represented as a generator even when

pumping – a real-time calculation explicitly represents the actual operating modes of these units.

2. Actual real-time bus loads. Off-line assessments may not be able to accurately account for changes in load diversity. Off-line models are often based on seasonal winter and summer peak load base cases. While representative of these peak periods, these cases may not reflect the load diversity that exists during off-peak and shoulder hours as well as off-peak and shoulder months – a real-time calculation explicitly accounts for load diversity. Off-line assessments may also reflect load reduction programs that are only in effect during peak periods.

3. Actual real-time breaker status.
Off-line assessments are often times bus models where individual circuit breakers are not represented; on-line models are typically node models where switching devices are explicitly represented. This allows for the real-time calculation to automatically account for split bus conditions and unusual topology conditions due to circuit breaker outages.

b. The calculation rate of the on-line assessment is much quicker and accurate than an off-line assessment as the on-line assessment immediately incorporates changes in system topology and generators. Facility trippings and outages are automatically incorporated into the real-time assessment.

**Options for Calculating Transaction Distribution Factors:** The preceding section outlined the proposed method to determine the effects of untagged market flows upon external flowgates. This section outlines various options that will ensure that the tagged transactions have as much if not more granularity within the NERC IDC. Any of the three options provides greater granularity in the calculations than currently provided by the IDC.

**Option 1:** PJM would calculate control area to control area distribution factors in the PJM EMS and upload these factors to the IDC for use in determining transaction impacts on constrained flowgates. PJM will calculate factors for all control area pairs of which PJM is a part, on all flowgates that have been identified for PJM/MISO congestion management coordination. The IDC will simply remove this set of factors from its calculations, and accept those calculated by PJM for use in its determination of transaction effects on the applicable flowgates. All transactions for which PJM is either the source or sink would be tagged as into or out of the entire PJM RTO. This option would provide the advantage of calculating transaction distribution factors based on marginal generation rather than a static model. The method by which transaction flow impacts are removed from network native load impacts in the Market Flow calculation requires further discussion.

**Option 2:** PJM would determine based upon the look-ahead solutions in the Unit Dispatch System the locations on the system where generation is expected to be marginal, and upload this information to the IDC. It may even be possible for PJM to indicate where the generation would move depending on the MW amount of curtailments that are necessary, if in fact the IDC would be able to use this information in its solution. This information would be transmitted in the form of adjustments to the generation participation factors that are already present in the IDC. The IDC could then utilize this information in the calculation of control area to control area distribution factors instead of the current methodology of utilizing a static model of all generators within a control area's boundaries. These locations could be on a zonal level (at a minimum) or as granular as individually identified generators. Note though, that this option carries the same limitation as Option 1 as far as explicitly accounting for transactions in the Market Flow calculation.

**Option 3:**

**Assumptions** ***(See "Market – Proxy – Source/Sink TDF Diagram" below)***

- A separate proxy bus will be designated within PJM along the PJM border for each source/sink outside PJM.
- PJM will calculate the TDF for flow between the PJM Market [marginal generator(s)] and each proxy bus for each "shared" flowgate. It is understood that the marginal generator(s) for one shared flowgate may differ from the marginal generator(s) for another shared flowgate.

- The IDC will calculate the TDF between each proxy bus and each source/sink outside PJM.
- Tag naming convention - Within the tag name, a dot would separate PJM from the name of the proper proxy bus within PJM. See the following examples:

For tags into PJM: Tag from **External Source** to **Proxy Bus** to **PJM.**
(eg. **TVA? PJM.TVAProxy**)

For tags out of PJM: Tag from **PJM** to **Proxy Bus** to **External Sink.**
(eg. **PJM.TVAProxy? TVA**)

## Procedure

PJM uploads the following to the IDC for each "shared" flowgate for both the current hour and next hour:

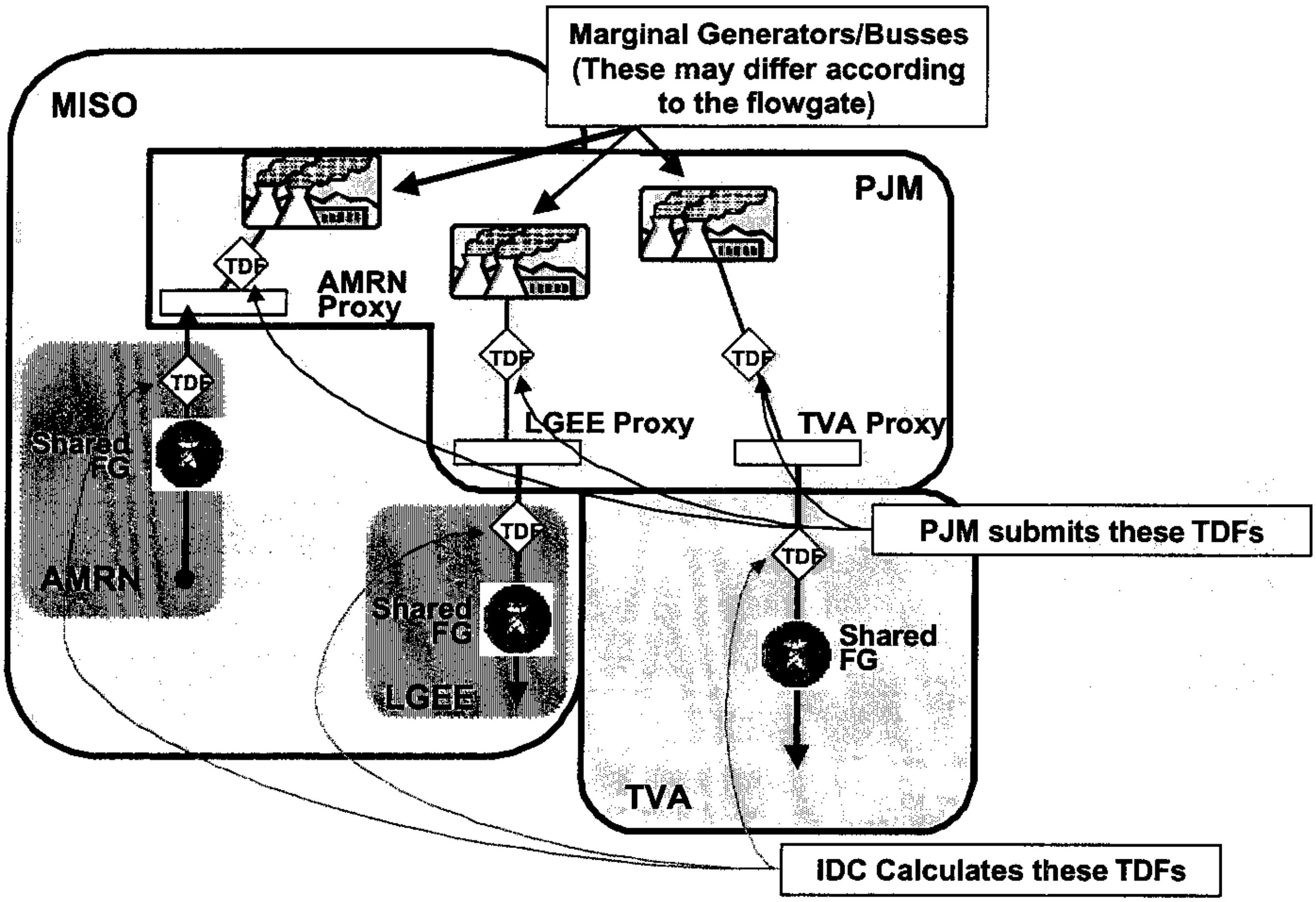
- Transfer Distribution Factor (TDF) from PJM Market to each proxy bus (for tags out of PJM).
- TDF from each proxy bus **into** the PJM Market (for tags into PJM).
- **Note:** Market Flow impacts (NNL + ED = MF) would also be uploaded to IDC for all "shared" flowgates

IDC would then calculate the total impact of each tag to/from PJM on a constrained flowgate by adding the following values:

- The TDF for the flowgate that was calculated and submitted by PJM for flows between the PJM Market and the proxy bus named in the tag
- The TDF for the flowgate that was calculated by the IDC for flows between the proxy bus and the external source/sink named in each tag

Once the IDC has calculated the total impact of each tag to/from PJM on the constrained flowgate as described above, it can proceed in compiling a proper and accurate curtailment list – just as is done today. By providing the TDFs as described in this option, it will also be possible to calculate - for each shared flowgate - the effect of the market response when a tagged transaction into or out of PJM is curtailed.

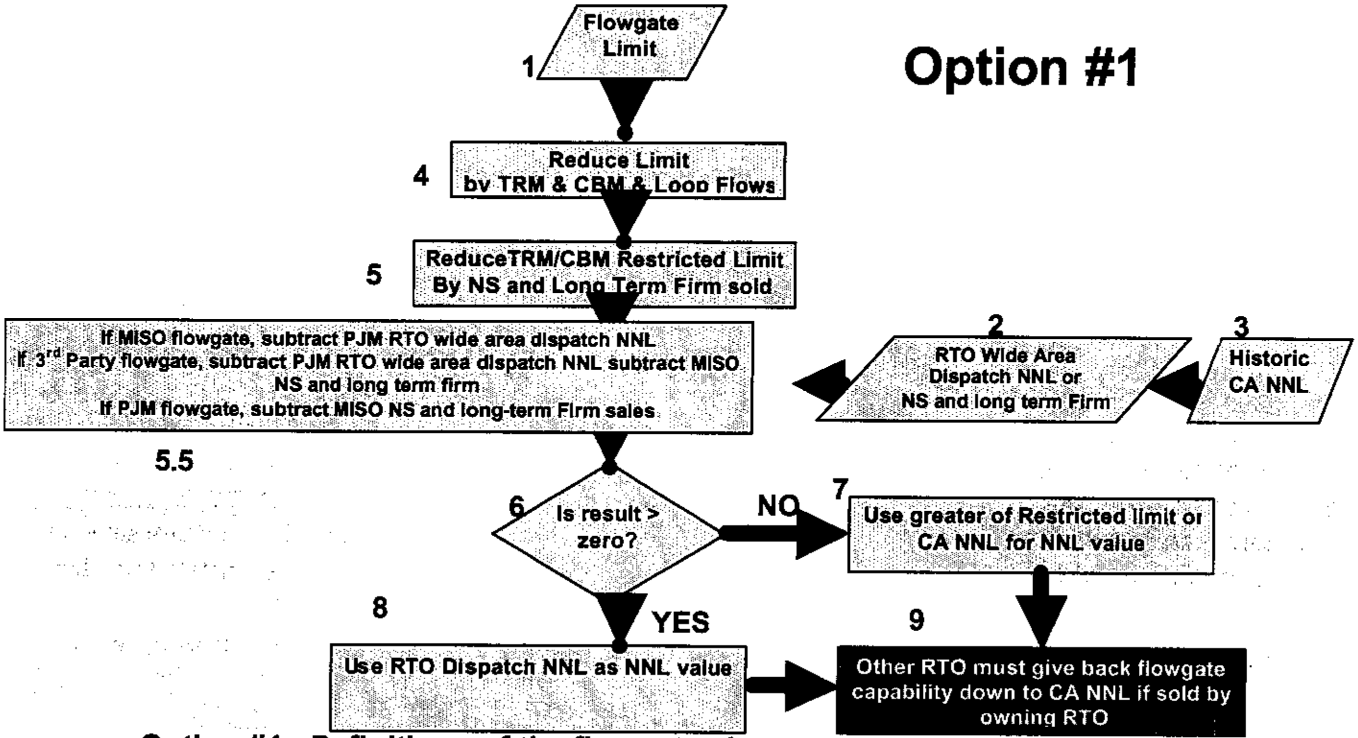
## Market – Proxy – Source/Sink TDF Diagram




**Determining the NNL Values --** To ensure that the NNL value is reliably constrained in both day ahead unit commitment and real time operations the NNL value determination can be represented by either of two options. In each Option the RTO's will implement, the **Michigan and Wisconsin hold harmless** settlement decisions (i.e., specified limits). If the RTO's determine a respective flowgate's NNL value to be less than the Wisconsin Michigan hold harmless values the RTO's will use the lesser of the NNL values in both Day Ahead and Real-time Operations. Both of these options will also decrement a flowgate's limit, by the

TRM/CBM margin and any Network Service and Long Term Firm sold. Additionally, both options consider Historical NNL values (or those NNL values that would have occurred if all control areas maintain their current configuration – and their generation would continue to serve the required native load). Historic NNL than refers to the configuration of the system rather than a particular value. Therefore, these Historic values are determined using the traditional determination of expected usage and the allocation of flowgate capacity. The RTO's will use a 12 month period to determine the contributions from firm interchange transactions and NNL by each LSE within the each of the market area. NNL contribution for each LSE will be the net of their positive and negative generation to load contributions for each generator designated to serve their load (ICAP, etc.). The generation to load calculation will be made for each LSE in the market to determine the PJM NNL and will be made for the historical LSEs that existed prior to the formation of the New PJM Companies with their traditional generation to determine the PJM NNL. The NNL would only consider generation that was designated to serve native load during the hour or hours that are selected as representative for the time period. The allocation will be dependent on the selection of the hour or hours in the month. If the peak hour is selected, will have an allocation over a broader base because more generators will be running and more transactions will be scheduled compared to an off-peak hour.

**OPTION 1 – NNL Determination** The following flowchart is a depiction of a proposed process in determining the NNL by considering the effect of an RTO Wide Area Dispatch



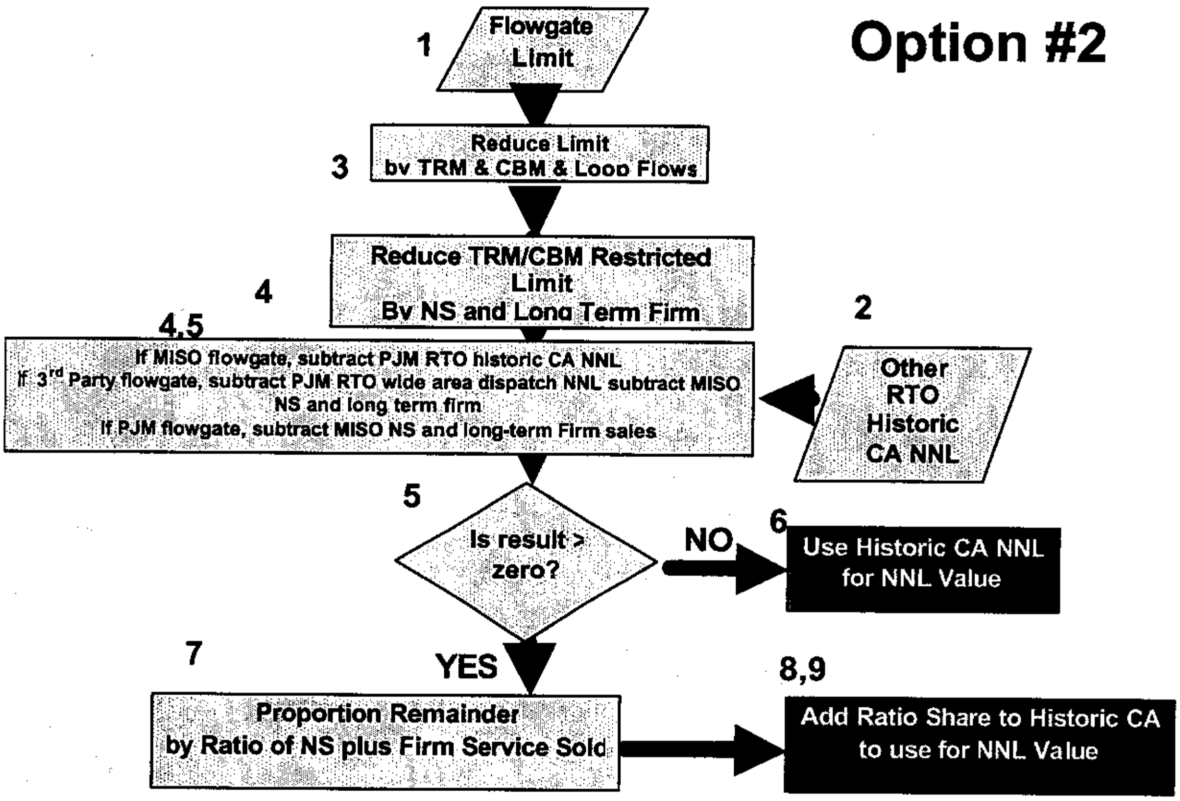

**Option #1 - Definitions of the flowgate elements**

1. Input – The Flowgate Limit, provided by TO/RC
2. Input – Market RTO Wide Area Dispatch – flows upon respective flowgate or NS and long term firm
3. Input – Using current Control Area footprints, of generations and loads, RTO calculates flows upon respective flowgate
4. RC/CA subtracts CBM and TRM values from flowgate capability and loop flow effects of other 3rd parties (i.e., IMO, TVA). Outputs a CBM/TRM/Loop Flow Restricted Capability
5. This restricted capability is further decremented by the owning RC/CA by the scheduled NS and Long Term Firm sold by the owning TP

5.5. RTO's subtract either the Wide Area Dispatch (MISO) or the NS and long term firm sales (PJM) from the restricted value.

6. Assess whether the Wide Area RTO Dispatch is greater than this restricted capability –
7. If it is greater– than the RTO will use the greater of the restricted limit or the Historic CA NNL
8. If it is not greater – than the other RTO utilizes the Wide Area Dispatch NNL as the NNL value
9. If the other RTO utilizes a value greater than the Historic CA NNL value, it must be able to give flowgate capability back to the owning RTO down to the CA NNL

value if the owning RTO requests it to support sale of Firm or Network transmission service




**Option #2 - Definitions of the flowgate elements**

1. Input – The Flowgate Limit, provided by TO/RC
2. Input – Using current Control Area footprints, of generations and loads, RTO calculates flows upon respective flowgate
3. RC/CA subtracts CBM and TRM values from flowgate capability and loop flow effects of other 3rd parties (i.e., IMO, TVA). Outputs a CBM/TRM/Loop Flow Restricted Capability
4. This restricted capability is further decremented by the owning RC/CA by the scheduled NS and Long Term Firm sold by the owning TP.

4.5 RTO's subtract either their counterparts Historic NNL from the restricted value.

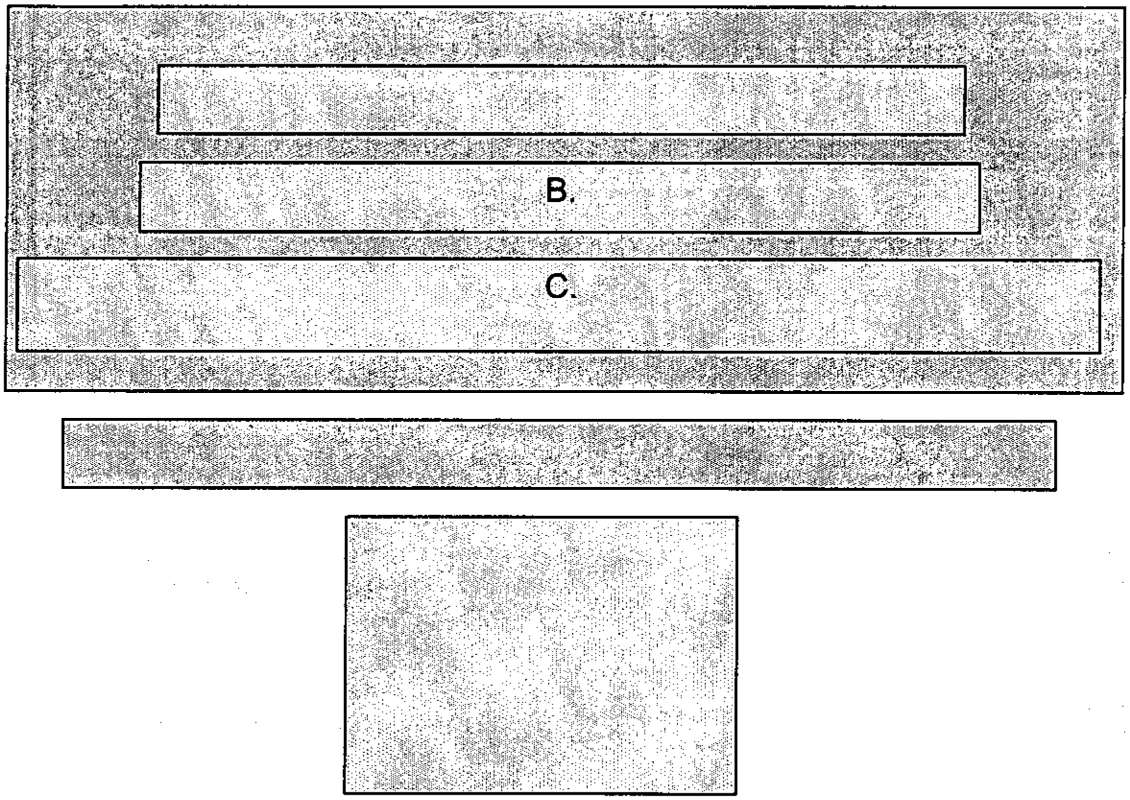
5. Assess whether this restricted capability is greater than the Historic CA NNL
6. If it is not greater – then the other RTO will use the Historic CA NNL as the NNL value
7. If it is greater – than there is a REMAINDER that will be apportioned based upon the firm and network service sold by the respective RTO's
8. This RTO proportion value is added to the historic NNL value and used as the NNL value in determining the market flows upon each flowgate

**NNL Options PRO's and CON's & Differences** – Each option's pros are the other options cons and visa versa. Option 1 has the pro of being able to fully maximize the use of the transmission system. Yet its con is that until MISO has a market that will allow it to redispatch, MISO does not have the redispatch option to permit it to handle the possibility of having to give back firm capability on flowgates its members do not own. In contrast, Option 2 provides a clear fixed number, that the RTO's can sell service against and operate in real-time. However, if underutilized margins are not idenitied and shared amongst the RTO's the transmission system can be underutilized. This underutilization could impact peak day operations.

The two options have the following differences:

1. Option 1, the RTO wide area dispatch is used as the value to subtract the NS and Long Term firm sales from. In contrast Option 2 subtracts these values for the Historic/Projected NNL.
2. In Option 1, if the remainder of the Wide Area RTO dispatch, less the NS and long term sales, is greater than zero an RTO could reliably maximize the capability of the transmission system as long as the owning RTO did not sell additional firm capability. In Option 2 there is not "return or give-back" capability so the NNL values are less likely to maximize the transmission system.

4. Using either of these options, MISO and PJM expect that the RTO's will fully integrate the value of enhanced AFC Coordination, Market Forces, and agreed upon limits to ensure that the most reliable NNL value is used in real-time operations.


B.
C.

1) AFC Calculations:

B. **METHOD C: .**

**d) Process to Utilize/Monitor Selected Flowgates –**

**1. Using NNL Flows Day Ahead**

a. PJM executes a Day-Ahead Unit commitment for all of the generators throughout the RTO footprint. PJM's day ahead unit commitment uses a network analysis model that mirrors the real-time model found within PJM's state estimator. As such, the day ahead commitment respects facility limits and forecasted system constraints.
b. Using the NNL value derived from one of the two options, PJM will enter this NNL value as a facility limit for the respective flowgate.
c. The Day Ahead Unit commitment will not permit flows to exceed this NNL value as it selects units for this commitment.
d. This constraining of PJM's day ahead commitment will occur regardless of whether the other Control Areas foresee the need for upcoming TLR actions.

**2. Using NNL in Real-time Operations**

**a. PJM Capabilities:**

1) PJM's real-time EMS has a very detailed state estimator and security analysis package that is able to monitor both thermal and voltage contingencies every few minutes. PJM's model will be at least as detailed as the IDC model for all of the identified/affected flowgates. Additionally, PJM will be continually working with MISO to ensure model synchronization. PJM will also initiate similar coordination whenever the IDC model is updated. The data PJM will utilize in its model will be either over ICCP links or over the NERC ISN.
2) The PJM state estimator and the Unit Dispatch System (UDS) will utilize all of these real-time internal flows and generator outputs to calculate both the actual and projected hour ahead flows on all of the selected flowgates.
3) Using real-time modeling, the PJM internal systems will be able to more reliably determine the PJM impact on flowgates created by the PJM dispatch, than the NERC IDC. The reason for this difference in accuracy is that the IDC uses very static SDX data that models generators as either at full output or off. In contrast PJM's calculations of system flows will utilize each PJM unit's actual output, updated every 5 minutes.

**b. PJM Real-time Actions**

1) PJM will have the list of 3rd party flowgates modeled as monitored facilities in its EMS.
2) The limits PJM will use for these 3rd party flowgates will be the NNL values determined by the final NNL Option (i.e., Option 1 or 2).
3) PJM will upload the real-time and projected flows as well as the delta of the NNL and actual flows on these flowgates to the IDC (every 5 or 15 minutes).
4) When the real time actual or projected flows exceed these NNL values on a flowgate and the Reliability Coordinator who has responsibility for that flowgate has declared a TLR 3a or higher, PJM will redispatch its system to restore the facility loading to the NNL value.
5) PJM will implement this redispatch by binding the flowgate as a constraint in the PJM Unit Dispatch System (UDS). UDS calculates the most economic solution while ensuring that each of the bound constraints is resolved reliably.
6) Additionally the PJM Operator will make any transaction curtailments as specified by the NERC IDC.
7) PJM's redispatch/relief will be faster than the 30 minutes required by TLR schedule curtailments.
8) The RC calling the TLR will be able to see the relief provided on the flowgate as PJM continues to upload the PJM contributions to the real-time flows on this flowgate.

**c. PJM Real-time Operations Example**

1) Suppose the Day-Ahead Market calculates a NNL limit of **100 MW** and the Market Flows imposed by the PJM RTO are determined to be 150 MW. The RTO will provide both the NNL limit being used, the current flow of 150, and the difference of 50 MW to the IDC. This 50 MW has the non-firm priority of 6-NN and is available for curtailment upon the occurrence of a TLR 3. The exact amount of curtailment is allocated by the IDC as is presently done for tagged non-firm service.

2) If the Market flow imposed by the PJM RTO is calculated to be less than the Day-Ahead limit, the difference provided to the IDC is 0 – PJM RTO does not redispatch for a TLR 3 event.

3) Additional redispatch (or 'curtailment') of Market Flow below the limit determined Day-Ahead occurs under a TLR 5 event. Essentially, Market Flows up to the limit determined in the Day Ahead-Market are treated as firm service (e.g. NNL).

**7. RESOLVED & OUTSTANDING ISSUES** – MISO and PJM have made progress in exploring and developing alternatives for resolving the reliability seam issues. The following provides a list of areas where there is agreement and areas where there are outstanding issues:

**MISO and PJM have agreed in principal on the following**

1. Market Flow Calculation – RTO's LMP engine would calculate market flows on internal and external flowgates. Proposed methodology for calculation is defined in this white paper. MISO has agreed RTO's LMP engine would calculate market flows given the following conditions are met:
   a. RTO LMP Model - Model will include areas outside its market with at least as good of detail as the NERC IDC model has. Must use NERC SDX data for topology/generation/load updates for areas not observable of real time data (ICCP/ISN).
   b. RTO Market Flows will be calculated and provided to NERC IDC all for internal flowgates where TLR may be called. This is required in order for NERC IDC to calculate proper TLR relief.
   c. Tagging In, out, or Across Markets – E-tagged transactions will reflect at least the granularity as provided before PJM market expands.
   d. Data Exchange - MISO/PJM Data exchange agreement will be completed and implemented before PJM market expands to ensure models are synchronized.

2. Control Area/Control Zone NERC Policy changes – Areas where changes will be required have been identified. A policy task force under the NERC Operating Reliability Subcommittee will recommend required policy changes or waivers.

## MISO and PJM Outstanding Congestion Management Seams Issues

1. Transmission Allocation – Two proposed options have been developed to determine magnitude of firm transmission allocation on each RTO's flowgates. It is uncertain if either method will be acceptable to all Stakeholders. Stakeholders have raised a concern that proposals will legitimize and provide entitlement to parallel flows. MISO is waiting for Stakeholder feedback on both options and any alternate proposals by Stakeholders before recommending either option or new alternative proposals.

2. Tagging In, out, or Across RTOs – Three options have been proposed to tag Interchange Transactions. MISO and PJM will wait for Stakeholder feedback before recommending any of the options. Need to ensure tagged flow is properly backed out of market flows.

3. Selection of Market/TLR Coordination Flowgates – Several study methods have been proposed. Proposed study methods may not be comprehensive enough or adequate to solve parallel flow problems. Stakeholders have expressed concern with proposed study methods. Present process for 5% threshold for impacts may not be adequate.

4. Adding Flowgates on the Fly – Need to ensure calculation of market flows and transmission allocation process allows for adding flowgates on the fly as needed.

5. ATC/AFC Coordination – Need to complete and implement ATC/AFC Coordination agreement. Need to ensure ATC/AFC Coordination agreement is integrated into allocation and prioritization of firm and non-firm uses of transmission system. Need to ensure PJM economic dispatch of energy does not get unfair advantage over MISO Priority 6 – Network Service from undesignated resources.

6. Congestion Management Implementation Steps – For Market/TLR Coordination Flowgates, need to define step-by-step process for utilizing market redispatch vs. TLR to obtain relief. Need method to track that RTO provided appropriate relief.

7. Coordination Agreement – Need to draft and post for comment proposed overall MISO and PJM Coordination Agreement that would include ATC/AFC Coordination Agreement, Data Exchange Agreement, Outage Maintenance and Coordination Agreement.

8. System Capabilities & Comparability - PJM is concerned that they are advocating approaches that significantly improve current utilization of technology (i.e, NERC IDC, SDX), and yet other parties will attempt to require additional complexities, when these parties current systems will not provide the granularity that PJM's system will provide. PJM is concerned that as a result of PJM providing far more granularity than any other entity, the PJM transactions are far more likely to be cut than more effective transactions from other control areas. As a result of other systems not providing similar granularity, the IDC will not be as effective and more transaction would require curtailment to provide system reliability. PJM also has concerns that some parties only want to maintain the status quo by enhancing the NERC IDC rather than enhancing system reliability by leveraging real-time applications.

9. Transmission Revenue - PJM is concerned that some stakeholder comments seem to focus more on maximizing transmission service revenue rather than managing the parallel flows issue. The solutions to the congestion management seams issue must provide for fully utilizing system capability with an equitable and reliable manner.

10. PJM is concerned that while it can calculate, track and redispatch to curtail its use of third party systems there seems to be little reciprocity available from other

systems. PJM is concerned with other control areas'/reliability coordinators' ability in particular to calculate its impact of Network service (designated and non-designated) on other systems.

11. PJM is concerned that current calculations and sales of firm service may have already oversubscribed the system. As a result, firm point to point service may have a higher priority on the NNL flows within an expanded market.

## 9. POTENTIAL VALUE

In this paper's problem statement there were three fundamental questions posed. When this proposal is compared to these questions, it is evident that this proposal's implementation could provide significant value to the Eastern Interconnection.

1. **How do non-market operational areas control system flows once the IDC loses current granularity?**
   - As markets expand fewer energy transactions may be tagged because these deals will be part of larger markets' single system dispatches. This proposal provides a new methodology to utilize both transaction curtailments and effective redispatch to control for flows generated from economic dispatch.
   - Because the RTO's will provide the IDC with market flow values the IDC should still be able to provide reliable solutions for the non-market areas to control system flows.

2. **Are there other ways to maintain and/or enhance IDC granularity?**
   - This proposal is attempting to provide the IDC significantly more granularity than the IDC ever has had. This granularity enhancement will be in the form of absolute visibility of PJM's real-time flows on a select set of external flowgates.
   - By utilizing multiple means to determine the most restrictive value for NNL, PJM's larger market operations will provide far more control of the flows currently being generated by the current set of control areas. One of these means of determining the NNL values ties AFC calculations and coordination to real-time limits. Another method ensures that PJM respects firm service allocated by a Transmission Provider on their flowgates.

3. **What are the curtailment priorities?**
   - Curtailment priorities are being addressed by separating economic dispatch flows from NNL flows, and permitting the redispatch of the system under TLR 3 to mitigate congestion.
   - Redispatch is typically a faster solution than implementing schedule curtailments.
   - Currently, redispatch is only available to Reliability Coordinators under TLR 6 and after the curtailment of firm service.

## 10. CONCLUSION

This Whitepaper is only the second phase of the conceptual design to resolve the Congestion Management seams issue. As a result of the stakeholders inputs and continued work between MISO, PJM, and the NERC community PJM and MISO will shortly be starting work in implementing the completed design. To facilitate this exchange of ideas, PJM and MISO are hosting the second Stakeholders Workshop. The workshop will be held **Jan 16th, 2003**, from 8 a.m. to 4 p.m. (CST) at the **Hyatt Regency O'Hare O'Hare International Airport** (9300 West Bryn Mawr Avenue River Road at Kennedy Expressway Rosemont, IL 60018;Telephone: 847-696-1234). MISO, PJM and SPP staff will facilitate discussion on proposals to mitigate parallel path flow issues between their service territories. Discussion of the proposals will center on the coordination of information related to the safe and reliable operation of the grid (i.e., this Whitepaper's proposal), including coordination of available transfer capability (ATC) and available flowgate capability (AFC) in the two regions. All interested parties are invited to attend by registering at the joint and common website - www.miso-pjm-spp.com. – under the "Info" portion of the site.

PJM and MISO welcome your input, issues, and recommendations so that this can be a solution the Eastern Interconnection can possibly use to improve reliability as the industry moves towards SMD.

## APPENDIX A – DEFINITION OF TERMS

**Control Zones -**

Within an RTO control area that is operating with a common economic dispatch, the RTO footprint is divided into control zones to provide specific zonal regulation and operating reserve requirements in order to facilitate reliability and overall load balancing. The zones must be bounded by adequate telemetry to balance generation and load within the zone utilizing automatic generation control.

**Generation Transfers -**

An RTO that covers a large geographic area and operates a single control area with a market with common economic dispatch but separate regulation zones, will monitor transfers of energy between regulating zones as part of the overall load and generation balancing function of the control area. The calculated difference between the actual generation within a regulation zone and the load within that zone is the generation transfer.

**LMP Based System or Market -**

An LMP based system or market utilizes a physical, flow-based pricing system to price internal energy purchases and sales.

**Locational Marginal Pricing (LMP) -**

Locational Marginal Pricing is the cost of supplying the next MW of load at a specific location, considering generation marginal cost, cost of transmission congestion, and losses. LMP's are equal when the transmission system is unconstrained. LMP's vary by location when the transmission system is constrained.

**Market Flows -**

Market flows are the calculated energy flows on a specified flowgate or transmission facility as a result of economic dispatch of generating resources within a large RTO Market.

**Network Native Load (NNL) -**

Network native load is load, within the RTO footprint, that the network customer designates for network integration transmission service and that is served by the output of any designated network resources.

**Security Constrained Dispatch -**

Security Constrained Dispatch is the utilization of the least cost economic dispatch of generating and demand resources while recognizing and solving transmission constraints over a single RTO Market.

## APPENDIX B – Possible NERC Policy Impacts

The MISO/PJM Policy Review Task Force is working with the MISO and PJM to identify what Policy changes may be necessary to enable the expansion of the LMP market over the PJM RTO footprint. Appendix B will be modified as necessary to address other impacts that may be noted by the Task Force as their work progresses. The Policy Review Task Force is responsible for coordinating its work with the applicable NERC Subcommittees so that Policy changes can be developed and provided to the NERC Standing Committees for approval.

### POLICY 1 – GENERATION CONTROL AND PERFORMANCE

As compliance to the Control Performance Standard (CPS) and Disturbance Control Standard (DCS) applies to the Control Area under NERC Policy 1, changes are anticipated if the RTO desires to report a consolidated CPS performance for the RTO "footprint" while enabling the Control Areas or "control zones" within the RTO to continue to report DCS compliance associated with their provision of Operating Reserves. The separate DCS reporting enables the Control Areas within ECAR, MAIN and MAAC to continue to participate as members of their respective Regional Reserve Sharing Group meeting that Region's reserve criteria. Specific sections of Policy 1 to be addressed are not listed, as the criteria for splitting the responsibility for reporting CPS versus DCS, and basing such reporting upon the metered boundaries of the RTO for CPS, versus the metered boundaries of the Control Areas or "control zones" for DCS, may require the addition of a section specifically to address the compliance reporting requirements.

### POLICY 3 – INTERCHANGE

The security-constrained economic dispatch calculated by the RTO every five minutes results in a net interchange value being provided to each Control Area or "control zone" within the RTO footprint. Under a LMP market, neither the transactions internal to the LMP market, nor the resulting energy flow between the Control Areas or "control zones" within the market used to enable the security-constrained economic dispatch, will be provided to the IDC through tagging. As part of the resolution of the MISO/PJM seams issues, another mechanism to populate operations information into the IDC for use in TLR procedures is proposed in this document to address the loss of tagged transaction information once the Control Areas move into the LMP market.

Policy 3 changes would be needed to reflect that an alternative methodology is acceptable for provision of information into the IDC other than tagging for multiple Control Areas or "control zones" operating within a single market dispatch. Likewise, details around curtailments and reloading of transactions associated with tagging will have to be addressed to incorporate the methodology accepted. At a minimum the following Policy 3 sections will be considered:

- Section D Interchange Transaction Modification; Requirement 2. Interchange Transaction modification for reliability-related issues. (and all sub-sections)
- Appendix 3A1 Timing Requirements for Re-Allocation when in a TLR Event
- Appendix 3A4 Curtailments and reloads
- Appendix 3D Transaction Tag Actions

## POLICY 9 – RELIABILITY COORDINATOR PROCEDURES

As part of the resolution of the seams issues brought before NERC, an alternative methodology will be proposed for providing information into the IDC for transmission assessment and curtailment other than through tagging individual transactions within the LMP market. With the new methodology, Policy 9 will have to define the responsibilities set forth for curtailment and the equivalent of reloading under LMP, similar to the responsibilities set forth for curtailment and reloading of tagged transactions. Reliability Coordinator responsibilities for next day analysis and current day operations will have to also consider the two methods of provision of information into the tools used for reliability assessment. Below are some of the Policy 9 sections that will be considered:

- Section A, requirement 1 Perform security analysis, subsection 1.1 data Needed by Noon on transactions
- Section A, Requirement 2 Study Results To Be Shared by 1500 hours CST
- Section C requirement 1, Interchange Distribution Calculator, Subsection 3.2.1.1 Use with an Interconnection Wide procedure (local procedure and re-dispatch0
- Appendix 9C1, General Comments Section needs to include word about equating "impact" to a transaction.

## ASSUMPTIONS

(1) All transactions into, out of, or across the Market RTO will be tagged according to the provisions stated in NERC Policy 3. The tag approval process assures that the necessary transmission service has been obtained from all applicable Transmission Providers.
(2) All tagged transactions implemented will be provided to the IDC according to Policy 3 through the tagging infrastructure for inclusion in the NERC TLR curtailment procedures and for FIST evaluations.
(3) In place of tagging transactions internal to the PJM market, systems will be implemented to provide information into the IDC according to the methodology accepted by stakeholders and NERC to reflect the PJM market operations and the resulting security-constrained economic dispatch.

(4) Similar to the use of tagged information in the IDC, information provided according to (3) will also be included in the NERC TLR curtailment procedures and FIST evaluations.

(5) The information provided to the IDC will be sufficient to enable the assessment of transmission impacts according to the Firm and Non-Firm priorities agreed upon in resolution of the MISO/PJM seams issues. It is currently proposed that the calculated "impacts" be shown in the IDC in Buckets 0, 6, and/or 7.

## APPENDIX C – To Be Published

## APPENDIX D.

# Parallel Flow Calculation Procedure Reference Document

**Approved by OC November 16, 2000.**

**Version 1, Draft 1**

[See also Appendix 9C1, "NERC TLR Procedure – Eastern Interconnection," Section F., "Transaction Contribution Factor"]

***Subsections***



## A. Introduction

This Reference Document explains how to calculate the contribution of Network Integration Transmission Service and Native Load on a TRANSMISSION CONSTRAINT under TLR Level 5 (5a or 5b).

The provision of Point-to-Point (PTP) transmission service as well as Network Integration (NI) Transmission Service and service to Native Load (NL) results in parallel flows on the transmission network of other TRANSMISSION PROVIDERS. When a transmission facility becomes constrained, NERC Policy 9C, Appendix 9C1, calls for curtailment of INTERCHANGE TRANSACTIONS to allow INTERCHANGE TRANSACTIONS of higher priority to be scheduled (a process called "Reallocation") or to provide transmission loading relief. An INTERCHANGE TRANSACTION is considered for REALLOCATION or CURTAILMENT if its TRANSFER DISTRIBUTION FACTOR exceeds the TLR CURTAILMENT THRESHOLD, which is typically 5% for MONITORED TRANSMISSION FACILITIES. In compliance with the Pro Forma tariffs filed with FERC by TRANSMISSION PROVIDERS, INTERCHANGE TRANSACTIONS using non-firm Point-to-Point TRANSMISSION SERVICE are curtailed first (TLR Level 3a and 3b), followed by transmission reconfiguration (TLR Level 4), and then the curtailment of INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service (TLR Level 5a and 5b). The NERC TLR Procedure requires that the curtailment of Firm Point-to-Point Transmission Service be accompanied by the comparable curtailment of Network Integration Transmission Service and service to Native Load to the degree that these three Transmission Services contribute to the CONSTRAINT.

To ensure the comparable curtailment of these three transmission services as part of TLR Level 5a or 5b, the NERC Parallel Flow Task Force (PFTF) has developed a method that allocates appropriate relief amounts to all firm PTP and NI/NL services in a comparable manner. A methodology, called the Per Generator Method Without Counter Flow, or simply the Per Generator Method, has been devised by the PFTF to calculate the portion of parallel flows on any CONSTRAINED FACILITY due to NI/NL service of each CONTROL AREA (CA). The Per

Generator Method has been presented to the Security Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC) and both committees have approved the methodology. The Interchange Distribution Calculator Working Group (IDCWG) has determined that the IDC tool could not be upgraded by the summer 2000 to automatically calculate the parallel flow contributions from NI/NL service. The SCS then directed the Distribution Factor Task Force (DFTF) to develop an interim procedure to implement the Per Generator Method as an integral part of TLR Level 5 for the summer of Year 2000. A description of this interim procedure is summarized in this reference manual.

## B. Basic Principles

The basic principles for curtailing Interchange Transactions using Firm Point-to-Point TRANSMISSION SERVICE curtailment based on NERC Policy 9C, Appendix 9C1, are given below:

1. All firm transmission services, including PTP and NI/NL services, that contribute 5% (the CURTAILMENT THRESHOLD) or more to the flow on any CONSTRAINED FACILITY must be curtailed on a pro rata basis.

2. For Firm PTP transmission services, the 5% is based on TRANSFER DISTRIBUTION FACTORS (TDFs). For NI/NL transmission services, the 5% is based on generator-to-load distribution factors (GLDFs). The GLDF on a specific CONSTRAINED FACILITY for a given generator within a CONTROL AREA is defined as the generator's contribution to the flow on that flowgate when supplying the load of that CONTROL AREA.

3. The Per Generator Method assigns the amount of CONSTRAINED FACILITY relief that must be achieved by each CONTROL AREA NI/NL service. It does not specify how the reduction will be achieved.

4. The Per Generator Method places an obligation on all CONTROL AREAS in the Eastern Interconnection to achieve the amount of CONSTRAINED FACILITY relief assigned to them.

5. The implementation of the Per Generator Method must be based on transmission and generation information that is readily available.

## C. Calculation Method

The calculation method is based on the Generation Shift Factors (GSFs) of an area's assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs are calculated from a single bus location in the base case. The LSFs are defined as a general scaling of the native load within each control area. The Generator to Load Distribution Factor (GLDF) is calculated as the GSF minus the LSF. Using the present NERC CURTAILMENT THRESHOLD of 5%, the reporting method looks for generation assigned to native load for which the Generation to Load Distribution Factor (GLDF) is greater than 5%. In cases where the Flowgate is considered limiting in the To → From direction, the sign of the GLDF is reversed. Generators are included where the sum of the generator PMAXs for a bus is greater than 20 MW, including off-line units (e.g., three 9MW generators add up to greater than 20 MW on a bus). Smaller generators that do not meet this criterion are not included. In the calculation process, all tested generators are listed as in-service and their MVA base is set to the PMAX value. SDX information is then applied for generator outages and deratings as applicable. This process may adjust the output of generators that are not intended to participate for an area. In such cases, the generation MVA base value should be adjusted (Percent = 0%) so that those units do not participate. All participation adjustments should be justifiable upon inquiry.

The original MVA base from the seasonal IDC case is not used because it is zero for many non-participating generators, such as nuclear units. The unit output in the case (PGEN) is not used because it may be turned on to a default 1 MW in some instances. The PGEN is not considered a good indicator of the unit's capability. The unit maximum capability (PMAX) is considered a good indicator of the unit ability to contribute.

A set of generation ownership data matches the generators to their Native Load areas. By default, the generator ownership data lists each unit as being 100% contributing to the Native Load calculations of the control area in which it is contained. There may be situations where the ownership would be less than 100%. Examples include: 1) a merchant generator who has tagged TRANSACTIONS; 2) a generator included multiple times for case modeling situations; or 3) a jointly-owned unit. Jointly-owned units may have multiple ownership listings to account for the multiple assigned areas. The joint ownership should be less than or equal to 100%.

Unit ownership can go beyond CONTROL AREA bus ownership. Units assigned to serve native load do not need to reside in the native load control area. However, units outside the native load control area should not be assigned when it is expected that those units will have tags associated with their transfers. Although the Native Load calculation has the ability to handle these ownership situations, the CONTROL AREAS and SECURITY COORDINATORS must supply the data or the default ownership will apply.

For each generator assigned to a CONTROL AREA'S Native Load, the amount of energy flowing on the CONSTRAINED FACILITY is calculated for the generator-to-Native Load transfer. The reporting is limited to those units that have a GLDF greater than or equal to 5%. The amount of transfer is based on the unit's maximum capability as listed in the base case (PMAX), and a comparison of Native Load level and the available generation assigned to the CONTROL AREA. The available assigned generation does not include small units that do not meet the 20 MW cutoff. When the available generation exceeds the load level, it is assumed that not all the generation is participating, and therefore, the PMAX values are scaled down by the load to generation ratio. If available, excess generation that is sold is expected to be tagged. If available assigned generation is less than the native load level, it is assumed that the area may be importing, and therefore the affected units are not scaled (scaling=1.00). Imports are assumed to be tagged.

***Summary***

If Available Assigned Generation > Native Load, Then Scale Down Pmax

If Available Assigned Generation < Native Load, Then Do not Scale Down Pmax

The amount of Energy on the Flowgate (EOF) that the native load area is responsible for is given as:

$$EOF_{area} = \sum EOF_{gen\ assigned\ to\ area}$$

The Energy on the Flowgate (EOF) for a specific assigned generator with a GLDF > 5% is given as:

$$EOF_{assigned\ gen} = (GLDF)(PMAX_{adjusted\ for\ SDX})(Percent_{Assigned}/100)(Scaling_{Area})$$

## D. Calculation Procedure

***SDX data requirements***

The factor calculation process uses available SDX data to update the current IDC seasonal case. Daily SDX data for transmission outages, generation outages and de-ratings, and daily load levels are applied to the calculation process. The SDX case updates are validated against tables to verify they match the seasonal case branch and generator lists. This is done to avoid process errors and to prevent the accidental insertion on new case data.

Transmission outages are applied by increasing the impedance to "9999" for out-of-service branches. The impedance adjustment is considered equivalent to the branch outage method, and it is preferred since it does not create islanding. Open transmission branches can also be placed back in-service based on SDX data.

Generator outages and de-ratings reported in SDX data are also applied to the case. The IDC seasonal case is initially adjusted such that the MVA base for all tested units is set to the PMAX value. By further adjusting the MVA base value, SDX generation data is then applied to the case to outage or de-rate units.

Daily SDX load levels are applied to the case. This information is used to update each control area's scaling factor. When daily load levels are not available through SDX, the seasonal value will be used as the default. The seasonal value is usually larger than the daily value.

The seasonal case is considered a solvable case. The applied daily SDX data makes the prepared daily case unsolvable. However, for factor calculation, a solved case is not required. Only a valid transmission topology is required.

Phase shifters are modeled as fixed angle. This is judged to be adequate for the present. However, in the relatively near future (when the MECS-IMO PARs are placed in service), ability to handle fixed MW operation will be needed.

***Posting of Contribution Factors***

The factors will be calculated by MAIN on a daily basis. The factors will be calculated some time after 1300 CST (or CDT) and will be posted before 1400 PM CST. This time was chosen because SDX data updates are required daily by 1300. The SDX data will be captured for those transmission and generation listings which cross 1401 CST.

A morning calculation may be performed to show the preliminary daily results. This run may be performed about 0800 CST. Specific midday re-runs may be requested by contacting MAIN. A message will be sent to the NERC DFTF after any new report postings. All reports will have a time stamp indicating when they were created. The reports will be posted on the MAIN web site at http://www.maininc.org/firmcurt/index.htm. This site is password protected for transmission use only. SECURITY COORDINATORS are expected to be given access to the reports via the SCIS system. Contact MAIN staff if access to the reports is needed. Reports are listed for each reliability flowgate. There is also a summary for each CONTROL AREA. Depending upon browser settings, the page may need to be reloaded/refreshed to view updated reports.

## E. Sample Calculation

An example of calculating firm transaction curtailments is provided in this section, assuming that the constrained flowgate is #3006 (Eau Claire-Arpin 345 kV circuit). The GLDFs for this flowgate are presented in Attachment 1. In this example, a total Firm PTP contribution of 708.85 MW is assumed to be given by the IDC.

From Attachment 1, the NI/NL contributions of all CONTROL AREAS that impact the CONSTRAINED FACILITY are listed below:

ALTE = 27.0 MW
ALTW = 41.1 MW
NSP = 33.1 MW
WPS = 26.2 MW
Total NL & NI contribution = 127.4 MW

Total Firm (PTP & NI/NL) contribution = 127.4 MW + 708.85 MW = 836.25 MW
NL & NI portion of total Firm contribution = 127.4/836.25 = 15.2%

PTP portion of total Firm contribution = 708.85/836.25 = 84.47%
Allocation of relief of the CONSTRAINED FACILITY to each CONTROL AREA with impactive NI/NL contribution is given below:

ALTE = 27.0 /127.4 x 0.152 = 3.2%
ALTW = 41.1 /127.4 x 0.152 = 4.9%
NSP = 33.1 /127.4 x 0.152 = 3.9%
WPS = 26.2 /127.4 x 0.152 = 3.1%

Assume that 50 MW of relief is needed. Then those CONTROL AREAS that impact NI/NL contribution and Firm PTP service are responsible for the providing the following amounts of flowgate relief:

Relief provided by removing Firm PTP = 0.845 x 50 = 42.25 MW
Relief provided by removing NL & NS contributions ALTE = 0.032 x 50 = 1.60 MW
Relief provided by removing NL & NS contributions ALTW = 0.049 x 50 = 2.45 MW
Relief provided by removing NL & NS contributions NSP = 0.039 x 50 = 1.95 MW
Relief provided by removing NL & NS contributions WPS = 0.031 x 50 = 1.55 MW

**Attachment 1**

## Native Load Responsibilities

Flowgate #: 3006 **Flowgate Name: EAU CLAIRE-ARPIN 345 KV**

| Common Name | Generator Reference System | Generator Shift Factor (GSF) | Percent Assigned | GLDF Gen to Load Factor | Pmax (MW) | Energy on Flowgate |
|---|---|---|---|---|---|---|
| **ALTE #364** | Avail Assigned Gen: 1,514<br>Load Level: 1,796<br>Scaling: 1.000 | ALTE_LD<br>Load Shift Factor: -0.097 | | | | |
| NED G1 13.8--1 CA=ALTE | 39000_NED_G1 | 0.022 | 100 | .1195 | 113.0 | 13.5 |
| NED G2 13.8--2 CA=ALTE | 39001_NED_G2 | 0.022 | 100 | .1195 | 113.0 | 13.5 |
| **Summary** | | | | | | **27.0** |
| **WPS #366** | Avail Assigned Gen: 1,691<br>Load Level: 1,910<br>Scaling: 1.000 | WPS_LD<br>Load Shift Factor: -0.193 | | | | |
| COL G1 22.0--1 CA=ALTE | 39152_COL_G1 | -0.094 | 32 | .0993 | 525.0 | 16.6 |
| COL G2 22.0--2 CA=ALTE | 39153_COL_G2 | -0.094 | 32 | .0993 | 525.0 | 16.6 |
| EDG G4 22.0--4 CA=ALTE | 39207_EDG_G4 | -0.118 | 32 | .0752 | 331.0 | 7.9 |
| **Summary** | | | | | | **41.1** |
| **NSP #623** | Avail Assigned Gen: 8,492<br>Load Level: 8,484<br>Scaling: 0.999 | NSP_LD<br>Load Shift Factor: 0.206 | | | | |
| WHEATON5 161--1 CA=NSP | 61870_WHEATO | 0.298 | 100 | .0919 | 55.0 | 5.0 |
| WHEATON5 161--2 CA=NSP | 61870_WHEATO | 0.298 | 100 | .0919 | 63.0 | 5.8 |
| WHEATON5 161--3 CA=NSP | 61870_WHEATO | 0.298 | 100 | .0919 | 55.0 | 5.0 |
| WHEATON5 161--4 CA=NSP | 61870_WHEATO | 0.298 | 100 | .0919 | 55.0 | 5.0 |
| WHEATON5 161--5 CA=NSP | 61871_WHEATO | 0.293 | 100 | .0874 | 57.0 | 5.0 |
| WHEATON5 161--6 CA=NSP | 61871_WHEATO | 0.293 | 100 | .0874 | 57.0 | 5.0 |
| WISSOTAG69.0--1 CA=NSP | 69168_WISSOT | 0.266 | 100 | .0601 | 37.0 | 2.2 |
| **Summary** | | | | | | **33.1** |
| **ALTW #631** | Avail Assigned Gen: 2,337<br>Load Level: 3,640<br>Scaling: 1.000 | ALTW_LD<br>Load Shift Factor: 0.065 | | | | |
| FOXLK53G13.8--3 CA=ALTW | 62016_FOXLK5 | 0.147 | 100 | .0819 | 88.5 | 7.3 |
| LANS5 4G22.0--4 CA=ALTW | 62057_LANS5_ | 0.116 | 100 | .0506 | 277.0 | 14.0 |
| LANS5 3G22.0--3 CA=ALTW | 62058_LANS5_ | 0.116 | 100 | .0505 | 35.8 | 1.8 |
| FAIRMONT69.0--3 CA=ALTW | 65816_FAIRMO | 0.151 | 100 | .0857 | 5.0 | 0.4 |
| FAIRMONT69.0--4 CA=ALTW | 65816_FAIRMO | 0.151 | 100 | .0857 | 6.0 | 0.5 |
| FAIRMONT69.0--5 CA=ALTW | 65816_FAIRMO | 0.151 | 100 | .0857 | 12.0 | 1.0 |
| FAIRMONT69.0--6 CA=ALTW | 65816_FAIRMO | 0.151 | 100 | .0857 | 7.0 | 0.6 |
| FAIRMONT69.0--7 CA=ALTW | 65816_FAIRMO | 0.151 | 100 | .0857 | 6.5 | 0.6 |
| **Summary** | | | | | | **26.2** |
| | | | | | | |

| Common Name | Generator Reference System | Generator Shift Factor (GSF) | Percent Assigned | GLDF Gen to Load Factor | Pmax (MW) | Energy on Flowgate |
|---|---|---|---|---|---|---|
| TOTAL Summary | - | - | - | - | - | 127.4 |

## APPENDIX E
## DRAFT NERC IDC Modification Requirements Per MISO & PJM LMP Implementation

### Background:

The requirement of this change order was developed to ensure the reliability of the bulk electric system is always maintained, and to ensure the NERC IDC is capable of determining accurate flow gate reductions representative of the entities actually creating the flows on the system. The expanded PJM footprint includes additional control areas being consumed into the LMP market, and involves the termination of using transmission reservations and NERC tags to represent system flows for those control areas. The NERC IDC must be capable of receiving flow gate impacts created by the LMP market.

Transactions going in and / or out, and through the PJM territory will continue to be tagged. Source / Sink bus points need to be determined in order to eliminate any type of gaming. During TLR, these tagged transactions will be curtailed as prescribed by the IDC, and could involve any of the current transmission priority buckets. The level of granularity and what E-tagging fields are used by the IDC to assign TDF factors to these transactions will be addressed in the near future.

In order to accomplish these changes necessary to incorporate the LMP markets into the IDC there will be NERC Policy, IDC software, algorithm, and database changes needed.

### PROPOSED CHANGE DESCRIPTION:

**IDC File Import Requirements:**

The LMP market impact files will be sent to the IDC or specified location at least every fifteen minutes. These files will include market impact information for two transmission priorities or categories, for every flow gate identified by the LMP Market agreement. This may not include all flowgates in the NERC BoF. IDC TDF calculations will continue to be done for the LMP market regions on all Flowgates to ensure that all tagged transactions from / into the market are curtailed properly during the TLR process.

The two transmission priorities that will be included in the LMP market impact file are:

a) Priority 6-NN (Economic Impacts of LMP Market)
b) Priority 7-F (Firm NNL Impacts)

The LMP engine will transfer two types of files to the IDC or specified location. A Current hour file will be sent at least every fifteen minutes, and one next hour file will be sent at (and no later than) 25-minutes after the hour.
Each file will contain flow impact information for priority 6-NN and 7-F for each identified flow gate. The LMP engine information associated with the flow gate calculations will be posted on the market OASIS for review.

The file transferred to the IDC will be in XML format. The field specifications will be identified when development begins.

If there is an error with the gathering/uploading or content of the LMP market impact file the values from the last good file will be used until a correct file can be retrieved. There should be an error sent to the RC to alert them of the file error.

**LMP Flow Gate Impact Calculation Protocol:**

*Flow gate impact protocol "proposals" are identified in the PJM / MISO Congestion Management White paper. The flow gate protocol process will be added to this NERC IDC change order once a defined process has been approved.*

**IDC Weighting Factor Algorithm Change Requirements:**

Since the LMP markets will be sending the flow impact for specified flowgates there will be no calculated TDF for that impact for use during the curtailment process. The weighting factor algorithm that is used to calculate the curtailments for priority 6-NN and 7-FIRM will need to be changed.

The curtailment and reallocation of the priority 6-NN bucket will need to be modified to be like the curtailment in the priority 7-FIRM bucket to allow the flow impact information to be used to assign curtailment amounts on a pro-rata basis (based on the MW level of the MW total to all such Interchange Transactions). Consequently al transactions using 6-NN Transmission Service will be put in the same sub-priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance. This change will also require a NERC Appendix 9C1 change in language.

The curtailment and reallocation of the priority 7-FIRM bucket will be the same with the exception that NO NNL Responsibility should be calculated for any of the CAs that are in the LMP market. The flow impact that will be sent to the IDC will already include the NNL portion for each area and there would be double counting if the 7-FIRM process also assigned NNL responsibility.

**IDC Curtailment Report Change Requirements:**

Non-firm schedule curtailments including transmission priority #1 through priority #5 will be prescribed for curtailment by the IDC as it is currently done.

Non-firm schedule curtailments of transmission priority #6 will include schedules identified by bucket #6 NERC tags, and by LMP market economic impacts. For non-firm priority #6 curtailments, the IDC curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP economic impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 6-NN bucket where the status will return to "Proceed". The LMP market economic impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

Firm schedule curtailments of transmission priority #7 will include schedules identified by bucket #7 NERC tags, by control area NNL reductions, and by LMP market firm. The firm LMP market impact value used by the IDC will include firm schedules and NNL impacts created by the market as one number. For firm priority #7 curtailments, the IDC firm curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP FIRM impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 7-FIRM bucket where the status will return to "Proceed". The LMP market Firm impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

**IDC Screen Change Requirements:**

Various IDC screen options will be modified in order to display LMP market impacts. For example, when selecting the "whole transaction" list option for a particular flow gate, the IDC will display the LMP priority #6 and #7 accordingly. Some examples are included below.

**NERC IDC Display Information:**
The following pages represent NERC IDC screen displays. The displays provide information with respect to how the IDC works today, and how the tool will work with the proposed LMP market change order. The Eau Claire – Arpin flow gate was used in the examples. The displays provide information for:

1) IDC "Whole Transaction list" for Eau Claire – Arpin as the tool is today.
2) IDC "Whole Transaction list" for Eau Claire – Arpin with the proposed LMP market change order.
3) TLR level 3B "Eau Claire – Arpin" Curtailment Report (50mw's of relief), as the tool works today, and with the proposed LMP market change order.
4) TLR level 3B "Eau Claire – Arpin" Curtailment Report (155mw's of relief), as the tool works today.
5) TLR level 3B "Eau Claire – Arpin" Curtailment Report (155mw's of relief), with the proposed LMP market change order.
6) TLR level 3B "Eau Claire – Arpin" Curtailment Report (100mw's of relief), with the proposed LMP market change order.

## Eau Claire – Arpin Flow Gate Information:

**The following IDC screen shot represents a NERC IDC "whole transaction" list as it works today.**

| Sink SC | Method | Tag Name | Reservation MW | Reservation Priority | Reliability Cap | Market Cap | Actual MW | Amount on Flowgate Schedule | Amount on Flowgate Active | TDF (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| EES | WL | MEC_TNSKDLJAN0278_EES | 150 | 1-NS | 150 | 150 | 150 | 11.0 | 11.0 | 7.1 |
| MISO | WL | OTP_OTPW010007985_MPS | 20 | 1-NS | 20 | 20 | 20 | 2.4 | 2.4 | 12.2 |
| PJM | CPM | NSP_NSPPOW0092573_PJM | 280 | 1-NS | 280 | 280 | 280 | 55.2 | 55.2 | 19.7 |
| | | Total for 1-NS | 450 | | 450 | 450 | 450 | 68.6 | 68.6 | |
| EES | WL | SECI_CRGL1ASH0107P_EES | 25 | 2-NH | 25 | 25 | 25 | 1.4 | 1.4 | 5.6 |
| MAIN | WL | MEC_AME010054962_PJM | 150 | 2-NH | 150 | 150 | 150 | 11.0 | 11.0 | 7.3 |
| MISO | CPM | NSP_NSPPOW0092737_OPPD | 6 | 2-NH | 6 | 6 | 6 | 0.8 | 0.8 | 13.3 |
| MISO | WL | WAUE_REMC010002263_MPS | 250 | 2-NH | 250 | 250 | 250 | 24.0 | 24.0 | 9.3 |
| TVA | WL | MEC_APMM1JAN3024_AECI | 50 | 2-NH | 50 | 50 | 50 | 3.0 | 3.0 | 6.0 |
| TVA | CPM | NSP_NSPPOW0092750_AECI | 350 | 2-NH | 350 | 350 | 350 | 69.0 | 69.0 | 19.7 |
| | | Total for 2-NH | 831 | | 831 | 831 | 831 | 109.2 | 109.2 | |
| PJM | WL | KCPL_CNCTET0005785_PJM | 53 | 3-ND | 53 | 53 | 53 | 3.1 | 3.1 | 5.8 |
| TVA | WL | NPPD_TEA01TEO3010_AECI | 60 | 3-ND | 60 | 60 | 60 | 4.3 | 4.3 | 7.2 |
| | | Total for 3-ND | 113 | | 113 | 113 | 113 | 7.4 | 7.4 | |
| MISO | CPM | ALTW_ALTMA10008672_ALTE | 79 | 6-NN | 79 | 79 | 79 | 12.2 | 12.2 | 15.4 |
| MISO | CPM | CE_ALTMA10008643_ALTE | 200 | 6-NN | 200 | 200 | 200 | 12.8 | 12.8 | 6.4 |
| MISO | CPM | CE_ALTMA10008651_ALTE | 150 | 6-NN | 150 | 150 | 150 | 9.6 | 9.6 | 6.4 |
| MISO | CPM | OTP_WEPM24000813J_WEC | 200 | 6-NN | 200 | 200 | 200 | 51.2 | 51.2 | 25.6 |
| MISO | CPM | WAUE_REMC010002261_WEC | 300 | 6-NN | 300 | 300 | 300 | 68.1 | 68.1 | 22.7 |
| TVA | WL | MEC_APMM1JAN2912_AECI | 8 | 6-NN | 8 | 8 | 8 | 0.5 | 0.5 | 6.0 |
| | | Total for 6-NN | 737 | | 737 | 737 | 737 | 86.4 | 86.4 | |
| MAIN | WL | MEC_CPS010101F00_AMRN | 30 | 7-F | 30 | 30 | 30 | 2.2 | 2.2 | 7.3 |
| MAIN | WL | MEC_MECBULET01105_CE | 360 | 7-F | 360 | 360 | 360 | 38.2 | 38.2 | 10.6 |
| MAIN | WL | MEC_MECBULET01106_AMRN | 11 | 7-F | 11 | 11 | 11 | 0.8 | 0.8 | 7.3 |
| MISO | CPM | ALTE_WPPI010040617_WPS | 10 | 7-F | 10 | 10 | 10 | 1.0 | 1.0 | 9.6 |
| MISO | CPM | ALTW_ALTMA10008479_ALTE | 154 | 7-F | 79 | 79 | 79 | 12.2 | 12.2 | 15.4 |
| MISO | CPM | ALTW_ALTMA10008656_ALTE | 50 | 7-F | 50 | 50 | 50 | 7.7 | 7.7 | 15.4 |
| MISO | WL | WAUE_UGPM010003879_MEC | 300 | 7-F | 300 | 300 | 300 | 17.1 | 17.1 | 5.7 |
| MISO | WL | WAUE_UGPM010003880_MEC | 200 | 7-F | 200 | 200 | 200 | 11.4 | 11.4 | 5.7 |
| MISO | CPM | WEC_CWPC010004010_WPS | 4 | 7-F | 4 | 4 | 4 | 0.4 | 0.4 | 9.6 |
| MISO | CPM | WEC_WPSM010001664_UPPC | 65 | 7-F | 65 | 65 | 65 | 3.8 | 3.8 | 5.9 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| TVA | WL | LES APMM1JAN2910 AECI | 40 | 7-F | 40 | 40 | 40 | 2.6 | 2.6 | 6.6 |
| TVA | WL | MEC AECIJAN1011 AECI | 4 | 7-F | 4 | 4 | 4 | 0.2 | 0.2 | 6.0 |
| TVA | WL | MEC APMM1JAN2911 AECI | 250 | 7-F | 250 | 250 | 250 | 15.0 | 15.0 | 6.0 |
| TVA | WL | MEC MECBULET01003 AECI | 150 | 7-F | 150 | 150 | 150 | 9.0 | 9.0 | 6.0 |
| | | Total for 7-F | 1628 | | 1628 | 1628 | 1628 | 63.5 | 63.5 | |
| [redacted] | | | | | | | | | | |

## Eau Claire – Arpin Flow Gate Information:

**The following IDC screen shot represents a NERC IDC "whole transaction" list with the proposed LMP market change order.**

| Sink SC | Method | Tag Name | Reservation | | Reliability Cap | Market Cap | Actual MW | Amount on Flowgate | | TDF (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | MW | Priority | | | | Schedule | Active | |
| EES | CPM | NewCo TNSKDLJAN0278 EES | 50 | 1-NS | 50 | 50 | 50 | 3.6 | 3.6 | 7.1 |
| PJM | CPM | NewCo NSPPOW0092573 PJM | 168 | 1-NS | 168 | 168 | 168 | 33.0 | 33.0 | 19.7 |
| | | Total for 1-NS | 238 | | 238 | 238 | 238 | 36.9 | 36.9 | |
| EES | WL | SECI CRGL1ASH0107P EES | 25 | 2-NH | 25 | 25 | 25 | 1.4 | 1.4 | 5.6 |
| PJM | CPM | NewCo AME010054962 PJM | 50 | 2-NH | 50 | 50 | 50 | 3.6 | 3.6 | 7.3 |
| EES | CPM | NewCo APMM1JAN3024 EES | 50 | 2-NH | 50 | 50 | 50 | 3.0 | 3.0 | 6.0 |
| FPL | CPM | NewCo NSPPOW0092750 FPL | 105 | 2-NH | 105 | 105 | 105 | 20.6 | 20.6 | 19.7 |
| | | Total for 2-NH | 230 | | 230 | 230 | 230 | 28.6 | 28.6 | |
| PJM | CPM | NewCo CNCTET0005785 PJM | 53 | 3-ND | 53 | 53 | 53 | 3.1 | 3.1 | 5.8 |
| TVA | WL | SPC TEA01TEO3010 AECI | 60 | 3-ND | 60 | 60 | 60 | 4.3 | 4.3 | 7.2 |
| | | Total for 3-ND | 113 | | 113 | 113 | 113 | 7.4 | 7.4 | |
| MISO | CPM | NewCo LMP Market Economic Disp. | | 6-NN | | | | | 79.3 | |
| PJM | WL | PJM LMP Market Economic Disp. | | 6-NN | | | | | 15.0 | |
| EES | CPM | NewCo APMM1JAN2912 EES | 8 | 6-NN | 8 | 8 | 8 | 0.5 | 0.5 | 6.0 |
| | | Total for 6-NN | 8 | | 8 | 8 | 8 | 94.8 | 94.8 | |
| PJM | CPM | NewCo CPS010101F00 PJM | 30 | 7-F | 30 | 30 | 30 | 2.2 | 2.2 | 7.3 |
| PJM | CPM | NewCo MECBULET01105 PJM | 160 | 7-F | 160 | 160 | 160 | 16.9 | 16.9 | 10.6 |
| MISO | CPM | NewCo LMP Market NNL | | 7-F | | | | | 120.0 | |
| PJM | WL | PJM LMP Market NNL | | 7-F | | | | | 16.0 | |
| TVA | CPM | NewCo APMM1JAN2910 AECI | 40 | 7-F | 40 | 40 | 40 | 2.6 | 2.6 | 6.6 |
| TVA | CPM | NewCo AECIJAN1011 AECI | 4 | 7-F | 4 | 4 | 4 | 0.2 | 0.2 | 6.0 |
| TVA | CPM | NewCo APMM1JAN2911 AECI | 142 | 7-F | 142 | 142 | 142 | 8.5 | 8.5 | 6.0 |
| TVA | CPM | NewCo MECBULET01003 AECI | 17 | 7-F | 17 | 17 | 17 | 1.0 | 1.0 | 6.0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total for 7-F | 993 | 993 | 993 | 993 | 167.4 | 167.4 |

[redacted]

## Eau Claire – Arpin Flow Gate Information:

**50MW of relief was required in this example. Only up to priority #3 was impacted.**

**The following IDC screen shot represents a NERC IDC "curtailment" list as it works today.**

| | | | | | |
|---|---|---|---|---|---|
| **SC Requestor:** | MISO | **CA Requestor:** | ALTE | **TLR level:** | 3B |
| **Requested Relief:** | 50 | | | | |
| **IDC MW Curtailed:** | 432 | **Trans. Curt.** | 8 | **Relief:** | 50 |

| SC | Tag Name | Method | Tag Marginal Priority | Schedule MW | Active MW | Curtail MW | MW Cap | Status | Relief Provided |
|---|---|---|---|---|---|---|---|---|---|
| EES | MEC TNSKDLJAN0278 EES | WL | 1-NS | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| TVA | NSP NSPPOW0092573 AECI | CPM | 1-NS | 168 | 168 | 168 | 0 | CURTAIL | 33.0 |
| EES | SECI CRGL1ASH0107P EES | WL | 2-NH | 25 | 25 | 25 | 0 | CURTAIL | 1.4 |
| MAIN | MEC AME010054962 AMRN | WL | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| SWPP | OPPD CRGL1ABJ0108J EDE | WL | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 2.8 |
| TVA | MEC SEINC0000500 AECI | WL | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.0 |
| PJM | KCPL CNCTET0005785 PJM | WL | 3-ND | 53 | 53 | 16 | 37 | CURTAIL | 0.9 |
| TVA | NPPD TEA01TEO3010 AECI | WL | 3-ND | 60 | 60 | 23 | 37 | CURTAIL | 1.7 |

[redacted]

****NOTE: The curtailment report above (when only including transmission curtailment priorities of bucket 0 – 5) will not change with the NERC IDC LMP market change order proposal.

## Eau Claire – Arpin Flow Gate Information:

**155MW of relief was required in the following example. Up to (and including) priority #6 was impacted.**

**The following IDC screen shot represents a NERC IDC "curtailment" list as it works today.**

| | | | | | |
|---|---|---|---|---|---|
| **SC Requestor:** | MISO | **CA Requestor:** | ALTE | **TLR level:** | 3B |
| **Requested Relief:** | 155 | | | | |
| **IDC MW Curtailed:** | 1208 | **Trans. Curt.** | 24 | **Relief:** | 155 |

| Sink SC | Tag Name | Method | Tag Marginal Priority | Schedule MW | Active MW | Curtail MW | MW Cap | Status | Relief Provided |
|---|---|---|---|---|---|---|---|---|---|
| EES | MEC TNSKDLJAN0278 EES | WL | 1-NS | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| TVA | NSP NSPPOW0092573 AECI | CPM | 1-NS | 168 | 168 | 168 | 0 | CURTAIL | 33.1 |
| EES | SECI CRGL1ASH0107P EES | WL | 2-NH | 25 | 25 | 25 | 0 | CURTAIL | 1.4 |
| MAIN | MEC AME010054962 AMRN | WL | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| TVA | MEC SEINC0000500 AECI | WL | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.0 |
| PJM | KCPL CNCTET0005785 PJM | WL | 3-ND | 53 | 53 | 53 | 0 | CURTAIL | 3.1 |
| TVA | NPPD TEA01TEO3010 AECI | WL | 3-ND | 60 | 60 | 60 | 0 | CURTAIL | 4.1 |
| MISO | ALTW ALTMA10008672 ALTE | CPM | 6-NN | 78 | 78 | 78 | 0 | CURTAIL | 12.0 |
| MISO | CE ALTMA10008643 ALTE | CPM | 6-NN | 100 | 100 | 67 | 33 | CURTAIL | 4.3 |
| MISO | CE ALTMA10008651 ALTE | CPM | 6-NN | 50 | 50 | 34 | 16 | CURTAIL | 2.2 |
| MISO | CE ALTMA10008652 ALTE | CPM | 6-NN | 50 | 50 | 34 | 16 | CURTAIL | 2.2 |
| MISO | CE ALTMA10008653 ALTE | CPM | 6-NN | 50 | 50 | 34 | 16 | CURTAIL | 2.2 |
| MISO | CE ALTMA10008654 ALTE | CPM | 6-NN | 50 | 50 | 34 | 16 | CURTAIL | 2.2 |
| MISO | CE MSCG01MS39921 ALTE | CPM | 6-NN | 25 | 25 | 17 | 8 | CURTAIL | 1.1 |
| MISO | CE MSCG01MS39922 WEC | CPM | 6-NN | 25 | 25 | 17 | 8 | CURTAIL | 1.1 |
| MISO | CE WEPM24000813Q WEC | CPM | 6-NN | 100 | 100 | 68 | 32 | CURTAIL | 4.4 |
| MISO | MHEB CRGL1AAA0107C WEC | CPM | 6-NN | 100 | 100 | 100 | 0 | CURTAIL | 29.9 |
| MISO | MPW WEPM24000813X WEC | CPM | 6-NN | 50 | 50 | 48 | 2 | CURTAIL | 5.5 |
| MISO | MP OTPW010007958 OTP | CPM | 6-NN | 50 | 50 | 29 | 21 | CURTAIL | 1.5 |
| MISO | MP OTPW010007975 OTP | CPM | 6-NN | 30 | 30 | 17 | 13 | CURTAIL | 0.9 |
| MISO | NSP WEPM24000813O WEC | CPM | 6-NN | 100 | 100 | 50 | 0 | CURTAIL | 14.2 |
| MISO | OTP WEPM24000813J WEC | CPM | 6-NN | 100 | 100 | 60 | 0 | CURTAIL | 12.7 |
| MISO | WAUE REMC010002261 WEC | CPM | 6-NN | 100 | 100 | 60 | 0 | CURTAIL | 13.2 |
| TVA | MEC APMM1JAN2912 AECI | WL | 6-NN | 8 | 8 | 5 | 3 | CURTAIL | 0.3 |

## Eau Claire – Arpin Flow Gate Information:

**155MW of relief was required in this example. Up to (and including) priority #6 was impacted.**

**The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.**

| | | | | | |
|---|---|---|---|---|---|
| **SC Requestor:** | MISO | **CA Requestor:** | ALTE | **TLR level:** | 3B |
| **Requested Relief:** | 155 | | | | |
| **IDC MW Curtailed:** | 1338 | **Trans. Curt.** | 10 | **Relief:** | 155 |

| Sink SC | Tag Name | Method | Tag Marginal Priority | Schedule MW | Active MW | Curtail MW | MW Cap | Status | Relief Provided |
|---|---|---|---|---|---|---|---|---|---|
| EES | NewCo TNSKDLJAN0278 EES | CPM | 1-NS | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| PJM | NewCo NSPPOW0092573 PJM | CPM | 1-NS | 168 | 168 | 168 | 0 | CURTAIL | 33.1 |
| EES | SECI CRGL1ASH0107P EES | WL | 2-NH | 25 | 25 | 25 | 0 | CURTAIL | 1.4 |
| PJM | NewCo AME010054962 PJM | CPM | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| EES | NewCo APMM1JAN3024 EES | CPM | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.0 |
| FPL | NewCo NSPPOW0092750 FPL | CPM | 2-NH | 105 | 105 | 105 | 0 | CURTAIL | 3.0 |
| PJM | NewCo CNCTET0005785 PJM | CPM | 3-ND | 53 | 53 | 53 | 0 | CURTAIL | 3.1 |
| TVA | SPC TEA01TEO3010 AECI | WL | 3-ND | 60 | 60 | 60 | 0 | CURTAIL | 4.1 |
| MISO | NewCo LMP Market Economic Disp. | CPM | 6-NN | | 80 | | 0 | Re-Dispatch | 80.0 |
| PJM | PJM LMP Market Economic Disp. | WL | 6-NN | | 15 | | 0 | Re-Dispatch | 15.0 |
| EES | NewCo APMM1JAN2912 EES | CPM | 6-NN | 50 | 50 | 50 | 0 | CURTAIL | 6.0 |

**FIRM CURTAILMENTS:**
****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the control areas located outside the LMP market that have an NNL reduction responsibility.

## Eau Claire – Arpin Flow Gate Information:

**100MW of relief was required in this example. Up to priority #6 was impacted.**

**The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.**

| | | | | | |
|---|---|---|---|---|---|
| **SC Requestor:** | MISO | **CA Requestor:** | ALTE | **TLR level:** | 3B |
| **Requested Relief:** | 100 | | | | |
| **IDC MW Curtailed:** | 1338 | **Trans. Curt.** | 10 | **Relief:** | 100 |

| Sink SC | Tag Name | Method | Tag Marginal Priority | Schedule MW | Active MW | Curtail MW | MW/ FG-Impact Cap | Status | Relief Provided |
|---|---|---|---|---|---|---|---|---|---|
| EES | NewCo TNSKDLJAN0278 EES | CPM | 1-NS | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| PJM | NewCo NSPPOW0092573 PJM | CPM | 1-NS | 168 | 168 | 168 | 0 | CURTAIL | 33.1 |
| EES | SECI CRGL1ASH0107P EES | WL | 2-NH | 25 | 25 | 25 | 0 | CURTAIL | 1.4 |
| PJM | NewCo AME010054962 PJM | CPM | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.6 |
| EES | NewCo APMM1JAN3024 EES | CPM | 2-NH | 50 | 50 | 50 | 0 | CURTAIL | 3.0 |
| FPL | NewCo NSPPOW0092750 FPL | CPM | 2-NH | 105 | 105 | 105 | 0 | CURTAIL | 3.0 |
| PJM | NewCo CNCTET0005785 PJM | CPM | 3-ND | 53 | 53 | 53 | 0 | CURTAIL | 3.1 |
| TVA | SPC TEA01TEO3010 AECI | WL | 3-ND | 60 | 60 | 60 | 0 | CURTAIL | 4.1 |
| MISO | NewCo LMP Market Economic Disp. | CPM | 6-NN | | 80 | | 45 | Re-Dispatch | 35.0 |
| PJM | PJM LMP Market Economic Disp. | WL | 6-NN | | 15 | | 8 | Re-Dispatch | 7.0 |
| EES | NewCo APMM1JAN2912 EES | CPM | 6-NN | 50 | 50 | 50 | 25 | CURTAIL | 3.0 |

[redacted]

**FIRM CURTAILMENTS:**

****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the control areas located outside the LMP market that have an NNL reduction responsibility.

## Item 4. Policy Review Task Force Report

### Discussion

At its September 18, 2002 meeting, the Review Team appointed a Policy Review Task Force to identify changes to policy required to support the envisioned implementation plans of MISO and PJM. Task Force members are Doug Hils, Dave Zwergel, Tom Bowe, Steve Corbin, Mark Fidrych, and Kim Warren. Task Force chair Kim Warren will present the findings and recommendations of the Task Force.

**Note: Appendix B of the PJM/MISO Congestion Management White Paper presents an overview of changes to policy required to support expansion of the PJM LJM market.**

# Kentucky Power
# d/b/a
# American Electric Power

## REQUEST

On page 11 of Mr. Baker's testimony, he states, "AEP's participation in PJM, and the resultant transfer of Kentucky Power's transmission facilities, will promote construction of properly located generation when that is the optimum solution."

a. Explain in detail how AEP's participation in PJM and the transfer of Kentucky Power's transmission facilities will promote construction of properly located generation.

b. Provide all studies, analyses, reports or other documents prepared by or for AEP or Kentucky Power that support this claim.

## RESPONSE

(a) PJM operates a liquid wholesale energy market. PJM's day-ahead market allows market participants to lock-in their sale and purchase prices a day in advance, and the LMPs resulting from the market provide valuable price signals that encourage the construction of generation additions at the places on the grid where they are most needed. Moreover, the PJM market provides the foundation for further customer oriented advances. For example, PJM has implemented a demand response program, with both emergency and economic components, that is integrated with the regional energy market. Qualified participants, by reducing load, can provide the same benefit to the grid as a generator that produces energy, and therefore can receive similar LMP-based payments under the economic demand response program. A regional program, such as PJM's, is likely to capture more of the consumer welfare benefits available from demand response than a single-utility program, operating in a small area, could accomplish.

This program is available both for industrial load as well as a pilot for residential load. PJM uses the LMPs calculated in the energy market as an economic means of managing transmission congestion. Specifically, when there is congestion on the transmission system, transmission customers have the option of avoiding curtailment by agreeing to pay transmission congestion charges, generally calculated as the difference in LMPs on either side of the constrained transmission element. LMP is an effective congestion management tool because it sends price signals that alleviate congestion by providing effective signals that allow the market participants to respond efficiently, such as providing construction of new generation and demand response initiatives. With LMP, only those entities using congested paths pay the increased charges. This avoids socialization of the costs. In this process, LMP provides price certainty and sends clear, visible price signals, as to the magnitude and frequency of transmission congestion that could be eliminated or reduced through either locating new generation in the congested area and/or expansion of the grid, as well as demand side response. In short, locational prices indicate where the problems are, and how much it might be worth to fix them.

(b) AEP has participated in industry forums on market-based pricing related issues to understand and analyze the LMP process. AEP believes that this mechanism should provide economic signals indicating the cost of delivering energy to specific locations. These signals, which are market-based --and not administrative type TLR-based--should provide adequate information to the market participants in order to analyze the need for infrastructure enhancement alternatives such as generation/transmission additions/modifications or demand response.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Provide a list of all regulatory approvals required to transfer functional control of AEP's transmission facilitates to PJM and the status of those approvals.

**RESPONSE**

Filings for approval (to the extent required) of transfer of functional control of AEP transmission facilities to PJM have been made in Kentucky, Indiana, Ohio and Virginia. Procedural schedules have been established in Kentucky and Indiana. The Indiana proceeding contemplates a hearing on March 19-21, 2003.

**WITNESS:** J. Craig Baker

**Kentucky Power**
**d/b/a**
**American Electric Power**

**REQUEST**

Describe and quantify the withdrawal penalties, if any, that would be incurred if AEP joined PJM and subsequently withdrew and the amount of any penalties that would be assigned to Kentucky Power.

**RESPONSE**

There are no withdrawal penalties.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

Provide a list of the differences between PJM's market rules and FERC's currently proposed SMD rules.

**RESPONSE**

AEP has not prepared a list of the differences between PJM's market rules and FERC's currently proposed SMD rules. However, the PJM has presented such a comparison at various committee and working group meetings. A copy of comparisons made by PJM and presented at various committee and working group meetings is included as Question No. 26, Attachment 1.

**WITNESS:** J. Craig Baker

# COMPARISON OF SMD TO PJM

## MUCH OF THE FUNDAMENTAL DESIGN OF SMD IS CONSISTENT WITH CURRENT PJM MARKET

- LMP based (for all nodes); ex post pricing
- CRRs = FTRs = Financial Transmission Rights
- All entities pay LMP-based Clearing Price
- Single Market Operator and System Operator
- Bid-based economic dispatch is basis for Day-ahead and Real-time Markets
- Voluntary generation unit commitment and dispatch
- Bilateral plus spot markets

## CONGESTION REVENUE RIGHTS MODEL

***Consistent with PJM Market Design*:**

- Property rights are allocated to customers who pay transmission access charges
  - Initially assigned to long-term firm customers, consistent with the existing pro forma tariff's right of first refusal; short-term and non-firm point-to-point customers would not receive CRRs.
- Provides for long-term CRR Auctions
- Encourages development of new hedging alternatives (i.e., PTP CRR Options)
- CRRs hedge against congestion charges
  - Acquire CRRs for receipt / delivery point(s)
  - Entitle holder to revenues from congestion between designated points to offset customer's congestion costs
  - If holder opts not to schedule service, still receive congestion revenue (i.e., the price differential between the receipt and delivery points).

***Different from PJM Market Design*:**

- Proposes Transmission Owner funding of CRR revenue shortfall (see below)
- Transmission scheduling priority for CRR holders (see below)

| [redacted] | [redacted] |
| --- | --- |
| SMD proposes that CRRs holders have a physical transmission scheduling priority. (159, 243)<br>Under the proposed rule, if there is a day-ahead or real-time transmission constraint that cannot be resolved, transactions without CRRs would be curtailed first. | FTRs are a financial congestion hedging mechanism, and they provide no physical transmission scheduling priority. Scheduling priority is based on whether the transmission customer has firm or non-firm transmission service.<br><br>Curtailment, if required, would occur pursuant to Transmission Loading Relief procedures. In real time transactions are curtailed by transmission priority (lowest priority non-firm up to highest priority firm). |
| The SMD proposes that the Transmission Owners will be responsible to cover the shortfall in congestion revenue that must be redistributed to CRR holders. (751) | PJM equally decreases the value of the FTRS if PJM does not collect 100% of the congestion revenue needed to cover all the FTRs. FTRs do not always provide a 100% hedge. |

# DAY-AHEAD ENERGY MARKET

| [redacted] | [redacted] |
| --- | --- |
| ➢ Voluntary Participation (269) – The NOPR proposes completely voluntary participation by both buyers and sellers in the Day-ahead Market while at the same time allowing both supply and demand to submit price-insensitive offers/bids. | PJM energy markets are voluntary in the sense that generation/load may choose to self-supply, enter into a bilateral transaction, or use the energy markets. However, generation resources that are designated as PJM Capacity Resources must bid into the Day-ahead market unless they are self-scheduled or unavailable because of an outage. Units that bid into PJM's Day-ahead market or self-schedule are dispatchable by PJM in real time. |
| ➢ The NOPR allows market participants to buy | PJM allows "up to" congestion bids but places a $25 cap on the |

| | |
|---|---|
| through transmission constraints (i.e., they pay congestion charges in lieu of curtailment). (210) The NOPR does not place a limit on the maximum amount of the "up to" bid. The NOPR also does not place a limit on the possible sources/sinks that may be included in such transactions. | amount of congestion that a party may include in the bid. For example, a party may bid 100 MW to go from X source to Y sink if the price difference between those two points does not exceed $25.<br><br>PJM does not place restrictions on the source and sink of such transactions, but it does prevent parties who acquired FTRs in the monthly FTR auction from profiting from their FTR position in the Day-ahead market (Otherwise, the party holding the FTR could cause congestion in the Day-ahead market with even just a few MWs depending on the source/sink path and then inc or dec and extract additional value for its FTR.) |
| The NOPR proposes the following additional features to increase market flexibility for the Day-ahead and Real-time market (307):<br><br>– Multi-hour block bids for transactions going in or out of PJM<br>– Multi-hour block demand bids (259) (i.e., the load submits a multi-hour block bid indicating a maximum price for the entire multi-hour period)<br>– Multi-part demand bids (272) (i.e., that indicate time and price constraints under which buyers are willing to purchase energy)<br>– Day-ahead Ancillary Services Markets (284) (Regulation, Spinning and Supplemental) | PJM allows generators to submit multi-part and multi-hour sell offers for generators and demand-response participants correlated to physical limitations of the generation units and load themselves (i.e., start up, no load, minimum run for generators, and minimum down times for demand response loads).<br><br>PJM does not have day-ahead ancillary service markets. |
| [redacted] | [redacted] |
| <u>Regulation</u> – The NOPR proposes to require financially binding Day-ahead Regulation Market. (284) | PJM has only a real-time Regulation market. |

| | |
|---|---|
| Spinning and Supplemental Reserves - The NOPR proposes to require a Day-ahead, financially binding Spinning and Supplemental Reserve Market. (284) | PJM does not have Real-time or Day-ahead spinning or supplemental reserve markets. PJM is working to implement a Real-time Spinning Market for December 1, 2002. |
| ➢ Real-time Ancillary Services Availability Bids (322) - The NOPR proposes to eliminate availability bids(i.e., offers indicating the price at which a generator is willing to be available to provide this service) for real-time spinning reserve services. It asserts that the types of costs reflected in availability bids are incurred only in the day-ahead time frame, not in real time. | PJM does not have a Real-time spinning market but does pay synchronous condensers for the costs they incur (i.e., O&M) to provide this service. |
| [redacted] | [redacted] |
| ➢ Hourly Changes to Generator Offer Prices in Energy Market (273,307) – The NOPR proposes to permit generators to submit new offer curves every hour. (Offer curves indicate how many MWhrs the generator is willing to provide at what price.)<br><br>➢ In addition, the NOPR proposes flexible transaction scheduling rules (i.e., rules for sales into and out of PJM) and self-scheduling of generation. | PJM's Day-ahead Market is based on scheduled hourly quantities and day-ahead hourly prices. The generator's bid covers all 24 hours in the day and is submitted prior to the operating day; the generator does not submit separate bids for each hour.<br><br>PJM's current market rules allow self-scheduled generators to change their schedules with only 20 minutes notice. |
| ➢ Incremental and Decremental offers / Bids in Energy Market(307) - The NOPR proposes that the Bids and Offers submitted in the Real-time Market be in the form of incremental and decremental adjustments to the Day-ahead market position for each load and generator. In other words, the NOPR appears to require a generator to offer the price the generator wishes to receive for the deviation. | PJM currently accepts Real-time offers in exactly the same form as was submitted in the Day-ahead market. (PJM uses incremental cost curves) Offers are not submitted for the incremental or decremental adjustment alone. |

| [redacted] | [redacted] |
|---|---|
| The SMD proposes to eliminate the <u>forward</u> physical transmission reservation system for managing external transactions. (152-153) All transmission service will fall under the Network Access Transmission Service (see below, "Transmission Service and Pricing" section). Transmission service, therefore, is not scheduled on a physical basis but rather a financial basis. | PJM schedules forward transmission service for external transactions using OASIS. |

# MARKET MONITORING

## THE FUNDAMENTALS OF SMD'S APPROACH TO MARKET MONITORING ARE CONSISTENT WITH CURRENT PJM MARKET MONITORING

- **Mitigation of local market power using ex ante offer caps based on generator cost.**
- **Safety net bid cap at $1,000/MWh**
- **Capacity/Adequacy construct (although the NOPR's construct differs from PJM's construct)**
- **Optional backstop measure for significant market issues (aggregate Automated Mitigation Procedure) (Although PJM does not presently use this approach, this is not inconsistent with PJM's practice.)**

**Consistent with PJM approach:**

- Autonomous of market participants
- Report to FERC and to independent RTO Board
- Defined monitoring of ISO

**Inconsistent with PJM Approach:**

- Autonomous of ITP management
- Administer system of specific penalties

| [redacted] | [redacted] |
|---|---|
| <u>Local Market Power Mitigation</u><br>➢ The NOPR states that mitigation must rely on must-offer obligations to mitigate physical withholding and bid caps to mitigate economic withholding (i.e., where the unit is the unit that would alleviate a local transmission constraint, or a "must-run" unit). (418)<br>➢ The "must-run" designation is not linked to the unit being designated as a Capacity Resource.<br>➢ The NOPR establishes an offer cap for such must-run units based on the unit's marginal cost plus an adder. (419-421)<br>➢ The NOPR addresses opportunity costs for energy-limited resources in determining the cap. (422-423)<br>➢ Mitigation would apply to both day-ahead and real-time markets.(424) | PJM's rules are consistent with the NOPR except for the proposed treatment of bilaterals to substitute for market power mitigation. |
| The NOPR addresses options for dealing with the risk of a forced outage of a unit in a load pocket: (412)<br>➢ A portion of available day-ahead capacity may be exempt from the bid-in requirement to reflect forced outage risk in real time.<br>➢ Allow generators to provide all available capacity in real time at a capped bid in lieu of bidding in the day-ahead market to accommodate generators that have significant risk or opportunity costs.<br>➢ If the generator receives a capacity payment, that payment compensates for the forced outage risk so that the generator should be obligated to deliver energy or to pay for substitute supply from another source. If the generator does not | PJM requires the generation owner of a must-run unit to replace the energy in real time if the unit does not run. The capacity market rules provide an incentive to run because the value of capacity declines as the forced outage rate of the unit increases. (The capacity value of the unit takes into consideration the forced outage rate of the unit.) |

| | |
|---|---|
| receive a capacity payment, then it should not have to bear the risk of a legitimate outage. | |
| The NOPR proposes to exempt sellers who control a small amount of capacity in the market (e.g., no more than 50 MW) from mitigation. (428) | PJM's rules provide no exemptions. |
| The NOPR proposes a series of minimum behavioral rules which would be monitored by the market monitor. (445) These rules would be accompanied by predetermined penalties. (446, 455) | PJM's rules contain no such penalties. |
| The NOPR establishes a safety net bid cap of $1000. Imports would be allowed to set the market clearing price up to the capped value. The market monitor may exempt units from the cap. (413) | ➢ PJM has a bid cap of $1000.<br><br>➢ Internal and external resources are treated identically in PJM . Both internal and external resources can offer energy in the day ahead market that can set the price both in the day ahead and real time markets. Neither internal nor external resources can change their offers in real time. Both internal and external resources are price takers in real time if they have not made a specific price offer during the day ahead market or during the reliability run on the day ahead of the operating day.<br><br>➢ The market monitor cannot exempt any unit from the bid cap. |
| [redacted] | [redacted] |
| Reserve Requirement set by Regional State Advisory Committee | PJM does the administrative analysis to determine an appropriate Reserve Margin level. The PJM Board approves the Reserve Margin level, and then PJM translates that into an obligation for each LSE according to the share of the PJM load they serve. |
| Minimum Reserve Requirement of 12% (installed capacity) over forecast peak | PJM does not have a minimum Reserve Requirement. Rather, PJM's Reserve Margin is set at a level calculated to achieve a loss of |

| | |
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| | load probability of no greater than one day in ten years. |
| Planning horizon is determined by region. NOPR discusses establishing requirement for period of three to five years into the future to promote the development of new generating resources and their ability to contribute to the satisfaction of LSE obligations. | PJM evaluates needed reserve levels over the next five years and sets the Reserve Margin based on a calculation that looks one year ahead based on the most recent forecasts of load and resources, among other factors. The market signals sent through the energy market and the five year projection of required reserves appear to have been sufficient to promote a significant level of generation development in PJM. |
| ➢ Loads must provide for allocated share of required resources.<br><br>➢ Loads must submit plans to meet resource needs of area, plans may include: (533, 536)<br>• generation with necessary transmission capability for delivery<br>• bilateral contracts backed by specific generating units (with transmission) with deliverability<br>• demand response with deliverability<br>➢ The NOPR suggests a point-to-point deliverability test, with each LSE being required to show that its capacity resources are deliverable to its load. (511, 514)<br><br>➢ Plans are audited by ITP<br><br>➢ No discussion of shifting of load responsibility related to retail access programs (or for any other reason) | ➢ PJM requires LSEs to meet a capacity obligation based on their share of the PJM load.<br><br>➢ We permit LSEs to satisfy their capacity obligations using their own generation resources, Active Load Management (technically, ALM reduces their obligation), bilateral contracts, or the PJM capacity credit markets (daily, monthly and multi-monthly markets).<br><br>➢ Resources used to satisfy obligations are committed to PJM. Commitment of resources and on-going resource performance is tracked by PJM.<br><br>➢ Similarity between NOPR and PJM's structure:<br>o The NOPR talks about resources being used to meeting capacity adequacy requirements of only one region (would need to be deliverable to that region and would be recallable to that region). PJM's current structure allows resources to determine which region it wishes to serve as a capacity resource, and once they decide to commit to PJM, they are recallable to PJM.<br><br>➢ PJM requires the resources that LSEs use to meet their capacity obligations to be deliverable to PJM. PJM's concept of |

| [redacted] | [redacted] |
|---|---|
| ➢ The NOPR proposes the implementation of regional planning processes across defined planning areas. PJM, MISO, and SPP are one such defined planning area. The NOPR requires that a regional plan be completed for each planning area within twelve months of the effective date of the order. (590) | ➢ PJM has a regional planning process that currently includes PJM and PJM West. The Joint and Common Market with the MISO and SPP will include regional planning across the MISO-PJM-SPP footprint. |
| ➢ The NOPR, in separate paragraphs, requires that the regional planning process identify beneficial transmission needed for reliability and economics and requires that the process should identify reliability and economic needs, leaving open the question of how and by whom those needs should be met. (473, 503) Following the identification of needs, the ITP will conduct an RFP process to solicit solution alternatives and then evaluate submitted proposals. If the RFP is unsuccessful, the ITP may then order transmission solutions that would be the responsibility of the affected transmission owner. | ➢ PJM conducts a fully integrated planning process. The process establishes a base-line system that is compliant with reliability criteria and preserves all existing long-term firm rights regarding access to the transmission system. PJM then evaluates market driven needs, such as generation interconnections, and identifies transmission system enhancements required to accommodate such market needs consistent with reliability criteria. Cost responsibility for transmission system upgrades is assigned on a cost causation basis. [The baseline establishes a starting point for analysis of market driven needs and cost allocation for required system upgrades.] |
| ➢ For regions with ITPs, the NOPR adopts participant funding (i.e., those who benefit from a particular project, such as a generator building to export power or load building to reduce congestion) pay costs of construction and receive CRRs.<br><br>➢ For regions without ITPs, the NOPR proposes that all costs associated with transmission projects are rolled in on a region-wide basis. | ➢ Cost responsibility for transmission system upgrades is assigned on a cost causation basis. |

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| | deliverability is a network deliverability concept, not that a particular resource is deliverable to a particular point in PJM. PJM dispatches the entire system to serve the load using network transmission service.<br><br>➢ PJM's structure specifically accommodates retail choice. The LSEs' capacity obligations are accounted for on a daily basis to allow for load responsibility to shift through retail access programs. A series of markets are operated by PJM to help facilitate the ability of load serving entities to satisfy their capacity obligations (in addition to the LSEs being able to use owned generation or bilateral contracts to meet their capacity obligations). PJM's capacity credit markets include daily, monthly and multi-monthly capacity markets. |
| ➢ Penalties are imposed on an LSE that did not satisfy the requirement to submit a plan (at the start of the planning horizon) with sufficient resources to meet it's obligation when the region is short of operating reserves (during the operating day) and that load serving entity is taking energy from the spot market.<br><br>➢ Penalty amounts start at $500 per MWh if an area is 1% short of operating reserve, $600 for 2%, etc.<br><br>Parties not providing reserves (and taking energy from the spot market) must be shed first if the region needs to shed load, if not possible they pay a $1,000 per MWh penalty. State regulators also notified of the party's failure to provide adequate resources. | How PJM LSEs meet their capacity obligations is much different than what the NOPR proposes, so the penalty structure currently in place in PJM for LSEs that fail to meet their obligation, is not comparable to the penalty structure proposed by the NOPR. The penalties that PJM has in place under its current capacity adequacy structure are significant and provide a strong incentive for LSEs to provide capacity to PJM control. |
| NOPR is ambiguous as to whether need the same capacity adequacy structure for all regions or whether there may be regional differences. | |

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| ➢ FERC states that Multi-State Entities could be an important component of the regional planning process. (474, 491, 524, 553) | ➢ Currently, the states are included in PJM's regional planning process. The PJM RTEPP is an open stakeholder process.<br><br>➢ Pursuant to the MOU between the PJM Board and the MACRUC member state public utility commissions, the states may communicate with the PJM Board of Managers, which approves the Regional Transmission Expansion Plan. |
| [redacted] | [redacted] |
| ➢ NOPR said that if CBM is going to be used, it must be used comparably and those who use it should compensate fairly for that use (i.e., any mechanism that allows for the use of this capability must apply equally to all) What is not clear is how tie capability will be utilized under SMD. If CRRs determine the priority of use of tie capability, then CRRs would need to be secured to use external generation to satisfy the capacity obligation. Perhaps CRRs could be utilized to preserve the benefits currently derived through CBM. | PJM includes the statistically determined capacity value of the transmission capability represented by CBM in the determination of the Installed Capacity Reserve Requirement. The requirement is less than it would be if that benefit were not considered and LSE's, therefore, are required to provide a slightly smaller amount of generating capacity to satisfy their obligations (currently 117% vs 120% of peak load). PJM withholds the transmission capacity associated with CBM from firm ATC in order to ensure the ability of PJM to utilize available generating capacity from neighboring systems during a PJM emergency. |
| [redacted] | [redacted] |
| ➢ The NOPR creates a single transmission service for all customers (bundled retail and unbundled and wholesale). (136) This service is called Network Access Transmission Service. Transmission service is available to any customer up to the full amount of the transfer capability, so long as the customer is willing to pay the applicable congestion charges. 140, 146) All accepted transactions must be physically feasible under a security-constrained system dispatch. (140) This service eliminates the distinctions between firm and non-firm by making all services firm, subject to the customer paying the cost of congestion (with CRRs as a financial hedge | ➢ PJM offers both Network Integration Transmission Service (NITS) and Point-to-Point Transmission Service. Load Serving Entities primarily use (NITS). PJM ensures that all accepted transactions are physically feasible. NITS limits the customer's use of this service to the amount of network load that customer has. Receipt and delivery points under NITS include individual nodes, zones, and trading hubs. |

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| to that congestion). (144) | |
| ➢ Embedded transmission cost would be recovered through an access charge for Network Access Service on all LSEs based on their respective shares of the system's peak load. (142, 169). FERC accepts license plate rates but inquires as to whether this should be just for a transition period with later movement to full postage stamp rates. FERC inquires as to whether rate methodologies can vary between RTOs based on recommendations of state advisory councils. FERC also seeks comments on whether bundled load should pay some transmission rate upon implementation of SMD or after a four year transition. (178) | ➢ Transmission Owners recover their revenue requirement through license plate rates and from receipt of an allocated portion of through and out revenues. Rates consist of both network and point to point transmission service.<br><br>➢ PJM recently sought to extend license plate rates in PJM West to match review of PJM East rate pricing. (PJM extended the license plate rate structure which was to expire in 2004 when PJM was to go to a system-wide rate.) |
| ➢ FERC's proposal is intended to eliminate rate pancaking between and within ISOs. (170) FERC proposes two methods for comment:<br>o Exporting region allocates a portion of its revenue requirement to importing region with all of the importing region's customers paying an uplift charge whether or not they import. (186)<br>o Importing region's transactions assessed an inter-regional charge to compensate exporting region's transmission owners. (187)<br><br>➢ Charges would then be assessed within the RTO by zone to assign costs to the zone within the RTO actually importing.<br><br>➢ FERC invites additional pricing proposals from the Regional State Advisory Councils. | ➢ All rate pancaking within the "PJM East" region was eliminated at the inception of PJM energy markets. The rate pancaking between "PJM East" and "PJM West" was eliminated at the start of PJM West markets with Allegheny's lost revenues being recovered by being netted against administrative cost savings to all PJM users.<br><br>➢ PJM charges a "through and out" rate for exports and wheel through transactions. (There is no charge for imports. Loads just pay for network transmission service.)<br><br>➢ FTRs are only assignable within the PJM/PJM West regions. FTRs do not go beyond PJM/PJM West into other Control Areas. They are, however, assigned within PJM/PJM West to those who pay for transmission system upgrades. |

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| ➢ CRRs would be assigned across RTOs, for example, by paying a portion of MISO Transmission Owners' revenue requirements, PJM load would be entitled to a proportionate share of MISO's CRRs. (189) | |

## GOVERNANCE

| [redacted] | [redacted] |
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| ITP Board is accountable to FERC, not the market participants; it should ensure: system reliability and operating efficiency, efficiently functioning markets, and short and long-term planning objectives. (558) | Board's primary responsibilities are to ensure: (1) the safe and reliable operation of the Interconnection, (2) the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Control Area, and (3) the principle that a Member or a group of Members shall not have undue influence over the operation of the Interconnection. |
| Stakeholder committees must be advisory, rather than function as a decision making body. (560) | Members Committee is not only advisory, but also can amend provisions of the Operating Agreement including energy market rules. |
| Requires six stakeholder classes: (1) generators and marketers, (2) transmission owners, (3) transmission-dependent utilities, (4) public interest groups, (5) alternative energy providers, and (6) end-users and retail energy providers. (561) | Members Committee is composed of five sectors: (1) generation owners (2) other suppliers, (3) transmission owners, (4) electric distributors, and (5) end-use customers. |

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| No specific Member voting protocol is identified. | 2/3 affirmative vote of Members, on a sector basis, is required for an action |
| Separate Regional State Advisory Committee advises the Board. (561) | Memorandum of Understanding with MACRUC regulatory commissions establishing liaison to the Board. |
| **Board Qualifications** | |
| NOPR proposes ITP Board of Directors of between 5 and 9 members. (562) | PJM has 8 Board members with its President as a non-voting Board member. |
| Qualifications in one or more fields: senior corporate leadership of a major publicly traded company; professional disciplines of finance, accounting, or law; electrical engineering; regulation of utilities; transmission system operations or planning; trading or risk management; information technology; and generation planning operation. (563) | Qualifications in fields of: corporate leadership at the senior management or board level; professional disciplines of finance or accounting, engineering, or utility laws and regulation; experience with concerns of transmission dependent utilities; experience in operation or planning of transmission systems; experience in commercial markets and trading and associated risk management. |
| No current or recent ties (two years) with market participants; divestiture of interests within six months. (564) | No ties with market participants for five years; divestiture of interests within six months |
| Annual financial disclosure Statements, available for audit by FERC. (564) | Annual certification of no direct financial interests. |
| **Selection of the Board** | |
| Nationally recognized search firm, retained by a Nominating Committee, supplies at least two names for each vacancy. (565) | Office of Interconnection retains search firm; no specific requirement to identify two candidates per vacancy. |

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| Nominating Committee composed of two members from each sector votes, by simple majority, to fill Board vacancies individually; FERC seeks comment on whether the Nominating Committee should vote on an entire slate rather than on individual candidates. (566-568) | Members Committee votes to fill Board vacancies by a two-thirds sector vote; nominating committee of the Board presents a slate to Members Committee, which votes on the entire slate. |
| FERC seeks comments whether CEO should be a non-voting member of the Board. (567) | President is a non-voting member of the Board. |
| Terms: staggered four year terms; term limit of two consecutive terms. (570) | Staggered three-year terms; no term limits. |
| **Board Succession** | |
| If an existing Board member wishes to serve a second term, stakeholders vote to determine whether the Board member does so. If vacancies remain, Nominating Committee process is followed. (572) | No separately specified process for existing Board members; part of normal election process. |
| Resignations and removal for cause: search firm identifies candidates; Nominating Committee "review[s] the list of candidates and propose[s] new board members" (571) | Vacancies between Annual Meetings are filled by vote of remaining Board members. |

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| **Other Matters** | |
| ➢ Communications between Members and the Board.<br>o No provisions in the SMD NOPR aside from establishment of stakeholder advisory committee. | ➢ PJM Board members attend the Members Committee and other committee meetings.<br><br>➢ PJM Board also communicates with members through the Liaison Committee.<br><br>➢ The Operating Agreement allows Members (minimum of 5) to create a user group to bring an issue directly to the Board.<br><br>➢ Ex Parte Member communications with the PJM Board are posted on the PJM web site. |

# INDEPENDENT TRANSMISSION COMPANIES

## FERC's position on the overall role of ITCs:

In the Translink Order, FERC indicated that an ITC can perform various functions "within its footprint" but indicated that functions such as planning and congestion management must be coordinated with the RTO. FERC's order made it clear that the split of functions would need to be reexamined once there is an integrated marketplace as anticipated in SMD. In the SMD Order, FERC praises the role of ITCs and seeks to revisit the Translink Order. It is not clear if FERC's SMD Order seeks to expand or limit which functions the ITC can undertake exclusively as compared to the RTO.

## PJM:

FERC issued an order, Alliance Companies, et al., 100 FERC P. 61,137 (2002) requiring PJM to file tariff amendments to address ITCs. On January 10, 2003 PJM filed two new attachments, pursuant to this order, to amend the PJM OATT and set forth the terms and conditions for ITCs to operate in the PJM region. This filing is pending approval by the FERC, and an effective date of March 12, 2003 is proposed for the changes.

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10/3/02

DMS 187505

# Kentucky Power
# d/b/a
# American Electric Power

## REQUEST

Provide the latest estimate of the cost of conforming PJM's market rules to the SMD rules and the amount that would be assigned to AEP and Kentucky Power.

## RESPONSE

PJM has not conducted such an analysis at this time because the SMD is only a proposal and not a final rule. FERC is preparing a white paper on SMD based on the comments received from the industry for the SMD NOPR. This white paper will be issued in April 2003.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

**REQUEST**

On page 5 of Mr. Baker's testimony, he refers to the intent of AEP. Commonwealth Edison, and Illinois Power to participate in PJM through an ITC, which would be managed by National Grid. Provide a detailed narrative description of this arrangement and its current status.

**RESPONSE**

In June 2002, AEP entered into a "Memorandum of Understanding Among and Between PJM Interconnection, LLC, National Grid, USA, and Participants in the Independent Transmission Company". AEP, Commonwealth Edison, and Illinois Power were parties to the MOU and were the proposed participants of the ITC. The MOU provided the framework for the parties to negotiate and implement the formation of an ITC operating under the PJM RTO. The obligations of the parties to the MOU included the development of definitive written agreements supporting the formation of the ITC, an ITC business plan, and an Implementation Plan for integration of the ITC and ITC Participant operations into PJM. The Implementation Plan was to include projects, timing, and budgets for a phased integration that would initially begin with ITC operations for transmission related functions (Day 1) and then integration into the energy market operations within PJM (Day 2). The MOU contemplated a 30-day development period to complete these obligations, and provided further definition in such areas as transmission rate design including revenue neutrality concepts, proposed Day 1 and Day 2 allocation of functions between the ITC and PJM, reserve requirement obligations, and the further evaluation of the use of existing Alliance Bridgco systems in the integration effort.

Because of the inability of the Parties to complete definitive agreements and other arrangements as contemplated by the MOU in a timely manner, the MOU has terminated and is no longer effective.

**WITNESS:** J. Craig Baker

# Kentucky Power
# d/b/a
# American Electric Power

## REQUEST

Provide the agreement that governs the allocation of transmission system costs among AEP's operating companies, a brief explanation of how the agreement assigns responsibility for transmission costs among the operating companies, and the amount of transmission investment responsibility assigned to Kentucky Power. How does Kentucky Power's assigned transmission investment responsibility compare to its actual per-books transmission investments?

## RESPONSE

The Transmission Equalization Agreement (TEA) assigns cost responsibility for EHV stations and transmission lines operated at 138 kV or higher voltage (Bulk Transmission Facilities) among the operating companies on the basis of each company's member load ratio. A copy of the TEA is included as Question No. 29, Attachment 1.

The most recent comparison of Kentucky Power's assigned transmission investment responsibility to its actual per books bulk transmission investment is shown in Question No. 29, Attachment 2, which is the January 2003 Statement of Settlement under the TEA. As shown on page 3 of 3, Kentucky Power is assigned approximately 7.3% of the costs associated with the AEP Bulk Transmission Facilities, while it owns, and receives payment under the TEA, for approximately 8.3% of the AEP Bulk Transmission Facilities.

**WITNESS:** J. Craig Baker

# TRANSMISSION AGREEMENT

by and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

OHIO POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS MODIFIED BY:

MODIFICATION NO. 1, DATED JANUARY 1, 1989

and

SUPPLEMENT A TO MODIFICATION NO. 1

Dated December 12, 1989

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984 by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY (Columbus Company), an Ohio corporation, INDIANA & MICHIGAN ELECTRIC COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power System (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, and (v) Ohio Company in Ohio and West Virginia; and

0.3 WHEREAS, the Members have entered into an interconnection agreement, dated July 6, 1951, with modifications thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, Appalachian Company, Indiana Company, Kentucky Company, and Ohio Company entered into an agreement, dated April 24, 1958, with modification thereto, (said agreement, as so modified, herein called Special Facilities Agreement) which fixed the terms and conditions under which the 345-kV transmission facilities interconnecting the AEP System and Commonwealth Edison Company (Special Facilities) were provided, owned, operated, and maintained; and

0.5 WHEREAS, the Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.6 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Extra High Voltage (EHV) Transmission System; and

0.7 WHEREAS, the Members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the EHV Transmission System would enhance equity among the Members for the continued development of a reliable and economic EHV Transmission System; and

0.8 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.9 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.10 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

## ARTICLE 1

## DESCRIPTION OF EHV TRANSMISSION SYSTEM

Mod. 1

1.1 The Bulk Power Transmission System covered by this Agreement shall include the following transmission facilities owned by the Members: (i) All transmission lines operating at a nominal voltage of 138-kV or higher, (ii) all facilities such as transformers, buses, switchgear, and associated facilities located at transmission substations operating at a nominal voltage of 345-kV and above including EHV/138-kV substations, and (iii) any other transmission lines and associated substation facilities at any voltage designated by the Transmission Committee as having been installed for the mutual benefit of all Members.

1.11 In determining the investments in the Bulk Power Transmission System referred to under subsection 1.1 (i) above, only those transmission line costs includable in Accounts 350 and 354-359, inclusive, of the Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees, as in effect on January 1, 1984, shall be used.

1.12 The investments in the Bulk Power Transmission System referred to in subsection 1.1 (ii) and (iii) above are amounts includable in the accounts listed in the preceding subsection 1.11 plus Accounts 352 and 353.

Mod. 1

1.2 All investments referred to in Section 1.1 above shall be determined annually as of the end of each calendar year and shall prevail as the basis for monthly settlement payments during the immediately following calendar year, provided, however, that if in any month a Member's investment pursuant to Section 1.1 shall be increased by the addition of facilities costing $10,000,000 or more, that Member's transmission investment shall be redetermined and, together with the investment of the other Members then prevailing, shall prevail as the basis for monthly settlements during the next and remaining months of the calendar year.

ARTICLE 2

OPERATION

2.1 Each Member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmission Committee and shall be known as the "Transmission Manager".

# ARTICLE 4

## AGENT'S RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To render to each Member as promptly as possible after the end of each calendar month a statement setting forth the settlements hereunder for such preceding calendar month, in such detail and with such segregations as may be needed for accounting, operating, or other proper purposes.

4.13 To carry out cash settlements under this Agreement. Settlements by the Members shall be made for each calendar month through an account (hereby designated and hereinafter called "TRANSMISSION ACCOUNT") to be administered by Agent. Payments to or from such account shall be made to or by Agent as clearing agent of the account. The total amount of the payments made by Members to the TRANSMISSION

ACCOUNT for a particular month shall be equal to the total amount of the payments made to the Members from the TRANSMISSION ACCOUNT for such month.

ARTICLE 5

DEFINITIONS OF FACTORS ASSOCIATED WITH SETTLEMENTS

5.1 Factors associated with settlements under this Agreement are defined as follows:

5.2 MEMBER LOAD OBLIGATION - A Member's internal electric load plus any firm power sales by the Member to affiliated and non-affiliated companies other than Members, which firm power sales by the Member are principally characterized by the Member's assuming the load obligation as its own firm power commitment and by the Member's retaining the advantages accruing from meeting the load.

5.3 MEMBER DEMAND - A Member's MEMBER LOAD OBLIGATION determined on a clock-hour integrated kilowatt basis.

5.4 MEMBER MAXIMUM DEMAND - The MEMBER MAXIMUM DEMAND in effect for a calendar month for a particular Member shall be equal to the maximum MEMBER DEMAND experienced by such Member during the twelve consecutive calendar months next preceding such calendar month.

5.5 MEMBER LOAD RATIO - The ratio of a particular Member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the MEMBER MAXIMUM DEMANDS of all the Members in effect for such month.

Mod. 1

Supp. 4 to Mod. 1

5.6 MEMBER BULK TRANSMISSION INVESTMENT - The aggregate dollar investment of a particular Member in its Bulk Power Transmission System, as described in Article 1, less the Investment Tax Credit generated by such investment.

Pursuant to the Order of the Federal Energy Regulatory Commission issued November 3, 1989 in Docket No. ER84-348-012, the Investment Tax Credit used in the determination of MEMBER BULK TRANSMISSION INVESTMENT amounts shall be the result of multiplying the investment tax credit generated by such Member's investment by the following respective factors:

i) Appalachian Company = 0.79127
ii) Columbus Company = 0.80245
iii) Indiana Company = 0.79220
iv) Kentucky Company = 0.79211
v) Ohio Company = 0.78515.

5.7 SYSTEM BULK TRANSMISSION INVESTMENT - The sum of the MEMBER BULK TRANSMISSION INVESTMENTS of all the Members.

5.8 MEMBER BULK TRANSMISSION OBLIGATION - The SYSTEM BULK TRANSMISSION INVESTMENT multiplied by the MEMBER LOAD RATIO of a particular Member.

5.9 MEMBER BULK TRANSMISSION SURPLUS - The difference between the MEMBER BULK TRANSMISSION INVESTMENT and MEMBER BULK TRANSMISSION OBLIGATION of a particular Member, when such MEMBER BULK TRANSMISSION INVESTMENT exceeds such MEMBER BULK TRANSMISSION OBLIGATION.

5.10 MEMBER BULK TRANSMISSION DEFICIT - The difference between the MEMBER BULK TRANSMISSION OBLIGATION and MEMBER BULK TRANSMISSION INVESTMENT of a particular Member, when such MEMBER BULK TRANSMISSION INVESTMENT is less than such MEMBER BULK TRANSMISSION OBLIGATION.

ARTICLE 6

SETTLEMENTS

6.1 As provided in Article 8 below, following the end of each month, the Members shall carry out cash settlements through the TRANSMISSION ACCOUNT.

6.2 BULK TRANSMISSION EQUALIZATION RECEIPT - Each Member having a MEMBER BULK TRANSMISSION SURPLUS (MBTS) shall receive a BULK TRANSMISSION EQUALIZATION RECEIPT (BTER), each month, in dollars from the TRANSMISSION ACCOUNT determined by the following formula:

BTER = MBTS X MCC

Where:

MCC = The particular Member's monthly carrying charge factor as listed below:

| | | | |
|---|---|---|---|
| i) | Appalachian Company | = | 1.4933% |
| ii) | Columbus Company | = | 1.5733% |
| iii) | Indiana Company | = | 1.5000% |
| iv) | Kentucky Company | = | 1.4950% |
| v) | Ohio Company | = | 1.4508%" |

6.3 BULK TRANSMISSION EQUALIZATION PAYMENT - Each Member having a MEMBER BULK TRANSMISSION DEFICIT (MBTD) shall make a BULK TRANSMISSION EQUALIZATION PAYMENT (BTEP), each month, in dollars to the TRANSMISSION ACCOUNT determined by the following formula:

BTEP = SBTER X MBTD/SMBTD

Where:

SBTER = The sum of all Members' BTERs

SMBTD = The sum of all Members' MBTDs

## ARTICLE 7

## TAXES

7.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member having an MBTS any tax related to the receipt of settlements calculated pursuant to Article 6 of this Agreement (such as sales, excise or similar taxes not included in such Member's MCC), such tax expense incurred by such Member that would not have been incurred were the transmission settlements hereunder not being made, such Member shall be entitled to reimbursement for such additional taxes by Members having an MBTD, i.e., in calculating the monthly settlements hereunder, such Member having an MBTS shall receive an amount in dollars equal to the sum of (a) the amount of settlement calculated pursuant to Article 6 of this Agreement plus (b) an amount sufficient to reimburse such Member for the amount of such additional taxes which it has incurred. Each Member having an MBTD shall pay such reimbursement in (b) above in dollars as determined by the formula in Section 6.3 of this Agreement.

ARTICLE 8

BILLINGS AND PAYMENT

8.1 All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month or other period to which such bills are applicable, or on the tenth day following receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at the Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of this Agreement.

ARTICLE 9

MODIFICATION

9.1 Any Member, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 10

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

10.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date on which the last of the following events shall have occurred (Effective Date):

(a) June 1, 1984;

(b) This Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule, under circumstances where the FERC (i) shall not have suspended this Agreement or any part thereof, or (ii) if suspended, at the end of the suspension period.

10.2 This Agreement shall continue in effect for an initial period from the Effective Date to December 31, 1990, and thereafter for successive periods of one year each until terminated as provided under subsection 10.3 below.

10.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of said initial period or at the expiration of any successive period of one year.

ARTICLE 11

TERMINATION OF SPECIAL FACILITIES AGREEMENT

11.1 The Members agree that the Special Facilities Agreement, dated April 24, 1958, and all supplements and amendments thereto shall terminate as of the Effective Date of this Transmission Agreement and that all further obligations among them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

ARTICLE 12

REGULATORY AUTHORITIES

12.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

12.2 It is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 13

ASSIGNMENT

13.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto duly authorized as of the day and year first above written.

APPALACHIAN POWER COMPANY

By John W. Vaughn

COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY

By ______

INDIANA & MICHIGAN ELECTRIC COMPANY

By William A. Black

KENTUCKY POWER COMPANY

By Robert E. Matthews

OHIO POWER COMPANY

By ______

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By ______

FEB 06 2003

AMERICAN ELECTRIC POWER

Date February 6, 2003

Subject AEP Transmission Agreement Statement Of Settlement for January 2003

From J.E. Price / K. A. Vines KAV

To Transmission Committee Representatives and Alternates:

| | | | | | |
|---|---|---|---|---|---|
| J. R. Sampson | - | Ft. Wayne | J. C. Baker | - | 1RP23 |
| R. G. Ronk | - | Roanoke | S. D. Liggett | - | Canton |
| S. P. Moore | - | 1RP4 | B. M. Pasternack | - | Gahanna |
| E. K. Wagner | - | Frankfort | P. B. Johnson | - | Gahanna |
| L. V. Assante | - | 1RP28 | Deloitte & Touche | - | 1RP26 |
| E. J. Brady | - | 1RP29 | B.L. Thomas | - | Richmond |
| J. K. Geels | - | Canton | D.F. Tiemann | - | 1RP28 |
| D. F. Tiemann | - | 1RP28 | | | |

Attached is the **January 2003** Statement of Settlement for the AEP Transmission Account pursuant to the AEP Transmission Agreement dated April 1, 1984, as Amended and supplemented. Please note that these figures for January will be restated in the near future when these preliminary investment figures undergo further review and become final and the associated Investment Tax Credit information for year-end 2002 becomes available. Also, please note that the previous page 4 of 4 in this settlement that trued up the Indiana Tax for the deficit members has been eliminated, inasmuch as the tax expired on 12/31/2002.

This Statement provides the amounts to be booked in transmission expense account 565.0003 for the month of January 2003.

Attachment

cc: D. W. Bethel - 1RP23
N. M. Lycakis - 1RP4

STATEMENT FOR THE MONTH OF
Jan-03

STATEMENT OF SETTLEMENT TO BE MADE
THROUGH THE TRANSMISSION ACCOUNT
APPLICABLE TO JANUARY 2003 BUSINESS

Pursuant to the Transmission Agreement, dated April 1, 1984,

by and among

Appalachian Power Company,

Kentucky Power Company,

Indiana Michigan Power Company.,

Ohio Power Company,

Columbus Southern Power Company,

and with

American Electric Power

as Agent.

as Amended by Modification No. 1, dated January 1, 1989,
and Supplement A (to Modification No. 1), dated December 12, 1989.

NOTE:
This statement provides amounts to be booked by the Pool Members in the AEP System Transmission Account 565.10 and the cash settlements to be made through the TRANSMISSION ACCOUNT administered by the Agent.

Prepared by: Kevin A. Vines
Transmission Operations Department
February 6, 2003

STATEMENT OF AEP SYSTEM TRANSMISSION ACCOUNT
Pursuant to the AEP System Transmission Agreement
dated April 1, 1984 as amended.
Applicable to JANUARY 2003 Business.

| AEP POOL MEMBER | PAYABLE TO POOL AGENT (DEBIT) SEE NOTE 1 $ | PAYABLE BY POOL AGENT (CREDIT) SEE NOTE 2 $ |
|---|---|---|
| APCO | 0 | 1,104,826 |
| KPCO | 0 | 408,667 |
| I&M | 0 | 3,028,898 |
| OPCO | 1,040,838 | 0 |
| CSP | 3,501,553 | 0 |
| TOTAL | 4,542,391 | 4,542,391 |

NOTE (1):
The Member(s) should record the applicable amounts as a debit to Operation and Maintenance Expense, Account 565.10 Transmission of electricity by other - AEP System Transmission Account with a corresponding credit to account 234.XX, Accounts Payable to associated companies - AEP Service Corporation, Transmission Agreement Agent.

REFERENCE: Page 3, Column 8, plus taxes from Page 4, Column 5.

NOTE (2):
The Member(s) should record the applicable amounts as a credit to Operation and Maintenance Expense, Account 565.10 Transmission of electricity by others - AEP System Transmission Account with a corresponding debit to Account 146.XX, Accounts Receivable from associated companies - AEP Service Corporation, Transmission Agreement Agent.

REFERENCE: Page 3, Column 7, plus taxes from Page 4, Column 4.

CALCULATION OF SETTLEMENTS PURSUANT TO THE
AEP TRANSMISSION AGREEMENT
FOR THE MONTH OF JANUARY 2003

FACTORS ASSOCIATED WITH SETTLEMENT

| AEP POOL MEMBER | MLR APP. I | MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) APP. II, COL. 6 $ | MEMBER BULK TRANSMISSION OBLIGATION COL. 3 ALLOC. USING MLR $ | MEMBER BULK TRANSMISSION SURPLUS $ | MEMBER BULK TRANSMISSION DEFICIT $ |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4)=(2)-(3) | (5)=(3)-(2) |
| APCO | 0.28237 | 825,286,966 | 751,301,428 | 73,985,538 | 0 |
| KPCO | 0.07287 | 221,220,692 | 193,885,098 | 27,335,594 | 0 |
| I&M | 0.20311 | 742,341,010 | 540,414,467 | 201,926,543 | 0 |
| OPCO | 0.25183 | 600,557,877 | 670,043,696 | 0 | 69,485,819 |
| CSP | 0.18982 | 271,291,928 | 505,053,784 | 0 | 233,761,856 |
| TOTAL | 1.00000 | 2,660,698,473 | 2,660,698,473 | 303,247,675 | 303,247,675 |

SETTLEMENT

| AEP POOL MEMBER | MONTHLY CARRYING CHARGE | BULK TRANSMISSION EQUALIZATION RECEIPTS $ | BULK TRANSMISSION EQUALIZATION PAYMENTS $ |
|---|---|---|---|
| | (6) | (7)=(4)*(6) | (8)=(5)/SUM COL. 5 *SUM COL. 7 |
| APCO | 1.4933% | 1,104,826 | 0 |
| KPCO | 1.4950% | 408,667 | 0 |
| I&M | 1.5000% | 3,028,898 | 0 |
| OPCO | 1.4508% | 0 | 1,040,838 |
| CSP | 1.5733% | 0 | 3,501,553 |
| TOTAL | --- | 4,542,391 | 4,542,391 |

APPENDIX I

## AMERICAN ELECTRIC POWER SYSTEM
## MEMBER LOAD RATIO SUMMARY

MONTH ENDING 12/31/2002

MEMBER LOAD RATIO
JANUARY 2003

| APPALACHIAN | KENTUCKY | INDIANA | OHIO | COLUMBUS |
|---|---|---|---|---|
| 0.28237 | 0.07287 | 0.20311 | 0.25183 | 0.18982 |

MLR MONTHLY MAXIMUM
60-MINUTE INTEGRATED MEGAWATT DEMAND
EXCLUDE AEP SYSTEM SALES

| | TOTAL | APPALACHIAN | | | KENTUCKY | | | INDIANA | | | | OHIO | | COLUMBUS | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| MO | | DA | HR | PEAK | DA | HR | PEAK | DA | HR | PEAK | DA | HR | PEAK | DA | HR | PEAK |
| 2 | 17973 | 04 | 19 | 5794 | 07 | 09 | 1393 | 04 | 19 | 3381 | 09 | 08 | 4537 | 04 | 19 | 2868 |
| 11 | 16442 | 22 | 18 | 5012 | 18 | 08 | 1189 | 27 | 08 | 3258 | 26 | 19 | 4326 | 26 | 19 | 2657 |
| 10 | 16713 | 03 | 16 | 4806 | 03 | 15 | 1049 | 01 | 14 | 3270 | 02 | 15 | 4387 | 03 | 15 | 3201 |
| 09 | 19609 | 04 | 16 | 5280 | 09 | 15 | 1212 | 09 | 15 | 4094 | 09 | 15 | 5175 | 09 | 16 | 3848 |
| 08 | 20647 | 05 | 15 | 5703 | 05 | 14 | 1326 | 01 | 15 | 4294 | 01 | 16 | 5284 | 01 | 17 | 4040 |
| 07 | 20515 | 29 | 15 | 5554 | 22 | 14 | 1268 | 22 | 13 | 4323 | 29 | 13 | 5360 | 22 | 16 | 4010 |
| 06 | 19860 | 25 | 15 | 5444 | 04 | 16 | 1269 | 24 | 15 | 4079 | 25 | 14 | 5292 | 24 | 16 | 3776 |
| 05 | 17043 | 37 | 17 | 4816 | 30 | 14 | 1093 | 31 | 14 | 3438 | 31 | 13 | 4610 | 31 | 16 | 3086 |
| 04 | 16246 | 18 | 16 | 4532 | 04 | 08 | 1105 | 18 | 14 | 3309 | 18 | 16 | 4383 | 18 | 16 | 2917 |
| 03 | 17987 | 01 | 08 | 5846 | 01 | 08 | 1419 | 04 | 10 | 3278 | 04 | 11 | 4550 | 04 | 20 | 2894 |
| 02 | 18051 | 05 | 08 | 5950 | 05 | 09 | 1412 | 05 | 08 | 3242 | 05 | 08 | 4550 | 27 | 20 | 2897 |
| 01 | 18029 | 02 | 09 | 6010 | 04 | 09 | 1551 | 08 | 08 | 3170 | 04 | 08 | 4501 | 07 | 19 | 2797 |

MLR MAXIMUM 60-MINUTE
INTEGRATED MW DEMAND EXPERIENCED
DURING PRECEDING 12-MONTHS
EXCLUDE AEP SYSTEM SALES

| | TOTAL | APPALACHIAN | KENTUCKY | INDIANA | OHIO | COLUMBUS |
|---|---|---|---|---|---|---|
| | 21284 | 6010 | 1551 | 4323 | 5360 | 4040 |
| TE/TIME | | 01/02 HR 09 | 01/04 HR 09 | 07/22 HR 13 | 07/29 HR 13 | 08/01 HR 17 |

APPENDIX II

MEMBER GROSS AND NET TRANSMISSION INVESTMENT
Per TRANSMISSION AGREEMENT, Dated April 1, 1984
as AMENDED and SUPPLEMENTED
PRELIMINARY BALANCES as of 12/31/2002

| AEP POOL MEMBER | MEMBER GROSS TRANSMISSION INVESTMENT (before ITC) $ | MEMBER GENERATED INVESTMENT TAX CREDIT $ | MEMBER ITC ADJUSTMENT FACTOR | MEMBER ADJUSTED INVESTMENT TAX CREDIT $ | MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) $ |
|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5)=(3)*(4) | (6)=(2)-(5) |
| APCO | 849,738,000 | 30,901,000 | 0.79127 | 24,451,034 | 825,286,966 |
| KPCO | 227,354,000 | 7,743,000 | 0.79211 | 6,133,308 | 221,220,692 |
| I&M | 768,444,000 | 32,950,000 | 0.79220 | 26,102,990 | 742,341,010 |
| OPCO | 617,978,000 | 22,187,000 | 0.78515 | 17,420,123 | 600,557,877 |
| CSP | 278,128,000 | 8,519,000 | 0.80245 | 6,836,072 | 271,291,928 |
| TOTAL | 2,741,642,000 | 102,300,000 | | 80,943,527 | 2,660,698,473 |

The Member Transmission Investment data shown above are preliminary as of December 31, 2002, compiled in accordance with Modification No. 1 to the Transmission Agreement, made in compliance with the August 2, 1988 FERC Opinion No. 311 requiring the inclusion of all EHV and 138-Kv lines plus EHV and sub-EHV facilities at EHV Stations.

The Member Investment Tax Credit Amounts have been calculated as of December 31, 2001 based on the yearly net additions to each Member's Bulk Transmission Investment, and the Investment Tax Credit rate applicable each year. Also, as provided by Supplement A to Modification No. 1 of the Transmission Agreement, the ITC is adjusted by the ratio of the cost of money and FIT components of the monthly carrying charge to the total carrying charge.